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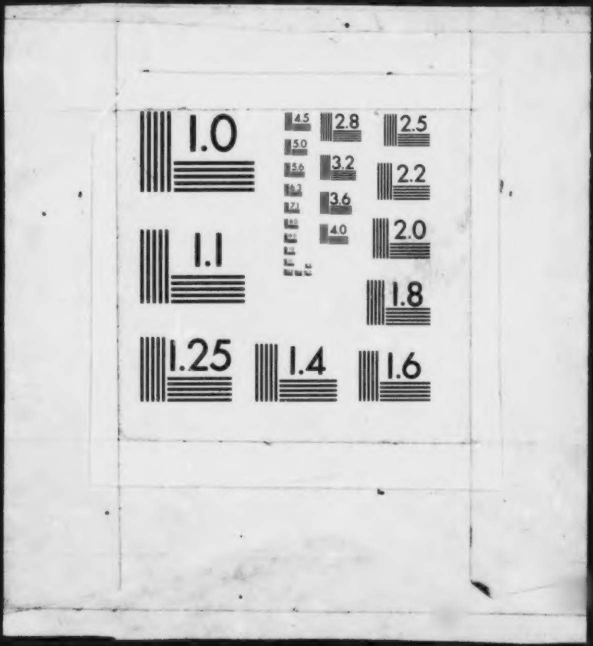
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Projected Impacts of Alternative Sulfur Dioxide New Source Performance Standards for Industrial Fossil-Fuel-Fired Boilers

Energy and Environmental Analysis, Inc
Arlington, VA

Prepared for

Environmental Protection Agency
Research Triangle Park, NC

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This report presents projected environmental, cost, and energy impacts of alternative sulfur dioxide (SO_2) air emission standards for new industrial fossil-fuel-fired steam generating units. These impacts are measured in terms of the projected change under current versus alternative air emission regulations. The analysis of environmental impacts focuses on changes in levels of air emissions. Cost impacts are evaluated in terms of incremental changes in the total annualized costs for boiler and pollution control equipment capital, operating, and fuel costs. Energy impacts are evaluated in terms of shifts in the demand between fuel types (e.g., coal or residual fuel oil versus natural gas).

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Emission Standards and Engineering Division

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

March 1985

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1. INTRODUCTION

This report presents projected environmental, cost, and energy impacts of alternative sulfur dioxide (SO_2) air emission standards for new industrial fossil fuel-fired boilers. These draft standards would supersede the emission regulations that currently exist in Subpart D of 40 CFR Part 60. The effects of the alternative SO_2 emission standards are assessed in this report. The methodology used to examine environmental, cost, and fossil fuel results projected under current and alternative emission regulations also is discussed.

For individual boilers, air emission regulations can play a significant role in determining boiler fuel choice and the levels of air emissions. Air emission regulations can result in measureable national and regional environmental, cost, and energy impacts, including changes in the types of fossil fuels combusted and changes in the level of air pollutant emissions generated by new industrial fossil fuel-fired boilers.

The analysis of alternative regulations is designed to highlight potential environmental, cost, and energy impacts. These impacts are measured in terms of the projected change under current versus alternative air emission regulations. The analysis of environmental impacts focuses on changes in levels of air emissions. Cost impacts are evaluated in terms of incremental changes in the total annualized costs for boiler and pollution control equipment capital, operating, and fuel costs. Energy impacts are evaluated in terms of shifts in the demand between fuel types (e.g., coal or residual fuel oil versus natural gas).

Current SO_2 emission regulations serve as the base case, from which all impacts are measured. Briefly, SO_2 emission control regulations in the base case for new industrial boilers are the current New Source Performance Standards (NSPS) for boilers with heat input capacity greater than 73 MW (250 MMBtu/hr). Current SO_2 emission regulations for all smaller boilers -- and for boilers larger than 73 MW (250 MMBtu/hr) heat input if more stringent than NSPS -- are State Implementation Plan regulations (SIP's).

This analysis examines projected impacts in the fifth year following proposal of standards. It was assumed that the recommended standards would be proposed in 1985 and that the impact analysis should, therefore, focus on projected results for new industrial fossil fuel-fired boilers installed in the five-year period between 1985 and 1990. The emissions and energy demand projections from new industrial fossil fuel-fired boilers presented in this report represent annual estimates for calendar year 1990.

This report addresses only fossil fuel (coal, oil and natural gas) consumption in large new industrial boilers. It does not analyze commercial-institutional boilers or nonfossil fuel-fired steam-generating units (i.e., wood or municipal solid waste combustion).

The balance of this report is presented in four parts. Section 2 presents the modeling approach employed to analyze the alternative standards and describes key assumptions and inputs. The potential 1990 national and regional impacts for the alternative standards are presented in Section 3. Section 4 summarizes the national 1990 economic impact results for the most stringent regulatory alternative examined.

2. METHODOLOGY

The methodology for assessing the environmental, cost, and energy impacts of the alternative air emission standards is described briefly in this section. The first part describes the model used to project the mix of industrial boiler fossil fuel demand, the level of air emissions, and the annualized cost of generating steam. The second part summarizes key modeling assumptions and model inputs used in this analysis. The third part briefly describes the criteria used to evaluate emission, cost, and energy impacts of alternative regulations.

2.1 ANALYTICAL APPROACH

This analysis is based upon results from the Industrial Fuel Choice Analysis Model (IFCAM), an energy demand model developed by Energy and Environmental Analysis, Inc. (EEA). In addition to generating fuel mix estimates, IFCAM projects levels of air emissions and steam generating costs.

IFCAM is a disaggregated process engineering model; models of this type simulate the effects of specific policies on new and existing technical alternatives, including innovative boiler designs and new pollution control equipment. IFCAM is designed to assess the impact of several factors on fuel choice decisions in the industrial sector, including fuel prices, energy and environmental policies, and capital and annual operating and maintenance (O&M) costs of firing alternative fossil fuels.

The U.S. Department of Energy (DOE) is the primary source for projections of overall industrial fossil fuel demand by region. IFCAM disaggregates DOE industrial fossil fuel demand forecasts into nine industrial subsectors. Energy use in each of these industrial subsectors then is divided into boiler and process heat applications.

Industrial boiler fossil fuel use is subdivided further to reflect the amount of fuel that will be used in new and existing boilers of different sizes and capacity utilization rates. Existing boilers are classified according to the type of fuel they are designed to fire and whether they can be retrofitted to fire alternative fuels. Eight size classes and five capacity utilization rate categories are delineated for both new and existing boilers.

Each new boiler is sited in an Air Quality Control Region (AQCR). New boilers are located within each AQCR according to historical siting patterns. Because State environmental regulations for existing and new boilers often vary by AQCR, IFCAM applies current regulations on an AQCR basis. These regulations are based on State air laws for existing fossil fuel-fired boilers.

The boilers represented in IFCAM are fired by one of several types of fossil fuels: coal, distillate fuel oil, residual fuel oil, or natural gas. IFCAM provides a choice between nine coal types that vary by sulfur, ash, and Btu content. Additionally, four residual fuel oil types that vary by sulfur content are available. The price of each fuel type can vary by region.

The pollution control equipment options available in IFCAM are presented in Table 2-1. For each fuel type (i.e., coal, oil, and gas), the least cost pollution control strategy that meets the alternative standard is calculated. The least cost strategy includes finding the lowest cost option in terms of the boiler, pollution control equipment, and annual fuel costs.

Based on the characteristics of each combustor (e.g., size, operating rate, pollution control requirements), capital and operating costs are generated for each fuel type. The fuel type associated with the lowest after-tax present value (including expected fuel expenses and boiler and pollution control equipment capital and O&M costs) of the total cost of generating steam over the boiler's investment period is selected.

The structure of IFCAM is summarized in Appendix A of this report.

2.2 KEY MODELING ASSUMPTIONS

This section presents the approach used in this analysis to model variables that could affect significantly the mix of fossil fuels demanded by industrial boiler owners.* These variables are:

---

*Other assumptions are summarized in Appendix A.

TABLE 2-1. INDUSTRIAL BOILER POLLUTION CONTROL EQUIPMENT OPTIONS IN IFCAM

Pollutant	Technology
SO_2	Flue gas desulfurization dual alkali[a] lime spray drying[b] sodium
PM	Single mechanical collector Dual mechanical collector Side stream separator Electrostatic precipitator Fabric filter
NO_x	Combustion modification low excess air staged combustion air

[a] Tray type scrubber.

[b] Combined SO_2/PM control system; includes a fabric filter.

- Regional industrial fossil fuel demand projections
- Energy policies
- Fuel price forecasts
- Environmental policies

2.2.1 Regional Industrial Fossil Fuel Demand Projections

DOE is the primary source of projections of total industrial fossil fuel demand. The rate of projected growth in industrial fossil fuel demand is a significant parameter because it determines, to a large extent, the expected demand for new industrial fossil fuel-fired boilers.

DOE does not project regional estimates of fuel consumption in industrial boilers. DOE does project regional estimates of total industrial fossil fuel demand for heat and power using the Energy Information Administration's (EIA's) Intermediate Future Forecasting System (IFFS). IFFS includes an econometric industrial energy demand model, the Purchased Heat and Power System (PURHAPS).[1,2]

The EIA regional industrial fossil fuel demand forecasts are summarized in Table 2-2. The ten Federal regions are illustrated in Figure 1. These projections are assumed to remain the same for regulatory baseline and alternative regulations examined in Sections 3 and 4 because the cost impacts are not expected to be sufficiently high to alter total projected energy demand.

The projections shown in Table 2-2 are a function of macroeconomic variable projections. For example, real growth in the Gross National Product between 1985 and 1990 is assumed to average 2.9 percent per year and real growth in manufacturing output between 1985 and 1990 is assumed to average 3.3 percent per year. The Federal Reserve Board industrial production index is expected to increase at a rate of 3.7 percent annually between 1985 and 1990.[3]

Not all of the projected net increase in industrial fossil fuel demand shown in Table 2-2 is attributable to new industrial boilers. A significant portion of this net increase is attributable to new process heat equipment.

2.2.2 Energy Policies

Energy policies contained in the National Energy Act of 1978 and the Omnibus Reconciliation Act of 1981 are key modeling assumptions in this analysis. These bills contain sections relevant to industrial boiler fuel choice, including:

TABLE 2-2. PROJECTED INDUSTRIAL FOSSIL FUEL DEMAND[a]
PJ (10^{12} Btu)

Region	1985 Refinery	1990 Refinery	1985 Industry[b]	1990 Industry[b]
1. New England	0 (0)	0 (0)	207 (196)	224 (212)
2. New York/New Jersey	48 (43)	43 (41)	512 (485)	541 (513)
3. Middle Atlantic	62 (59)	57 (54)	946 (897)	1,017 (964)
4. South Atlantic	46 (44)	43 (41)	1,615 (1,531)	1,728 (1,638)
5. Midwest	107 (101)	99 (94)	2,339 (2,217)	2,499 (2,369)
6. Southwest	509 (482)	473 (448)	2,915 (2,763)	3,180 (3,014)
7. Central	26 (25)	25 (24)	628 (595)	668 (633)
8. North Central	34 (32)	32 (30)	557 (528)	627 (594)
9. West	127 (120)	117 (111)	733 (695)	817 (774)
10. Northwest	33 (31)	30 (28)	442 (419)	510 (483)
U.S. Total	992 (937)	919 (871)	10,894 (10,326)	11,811 (11,194)

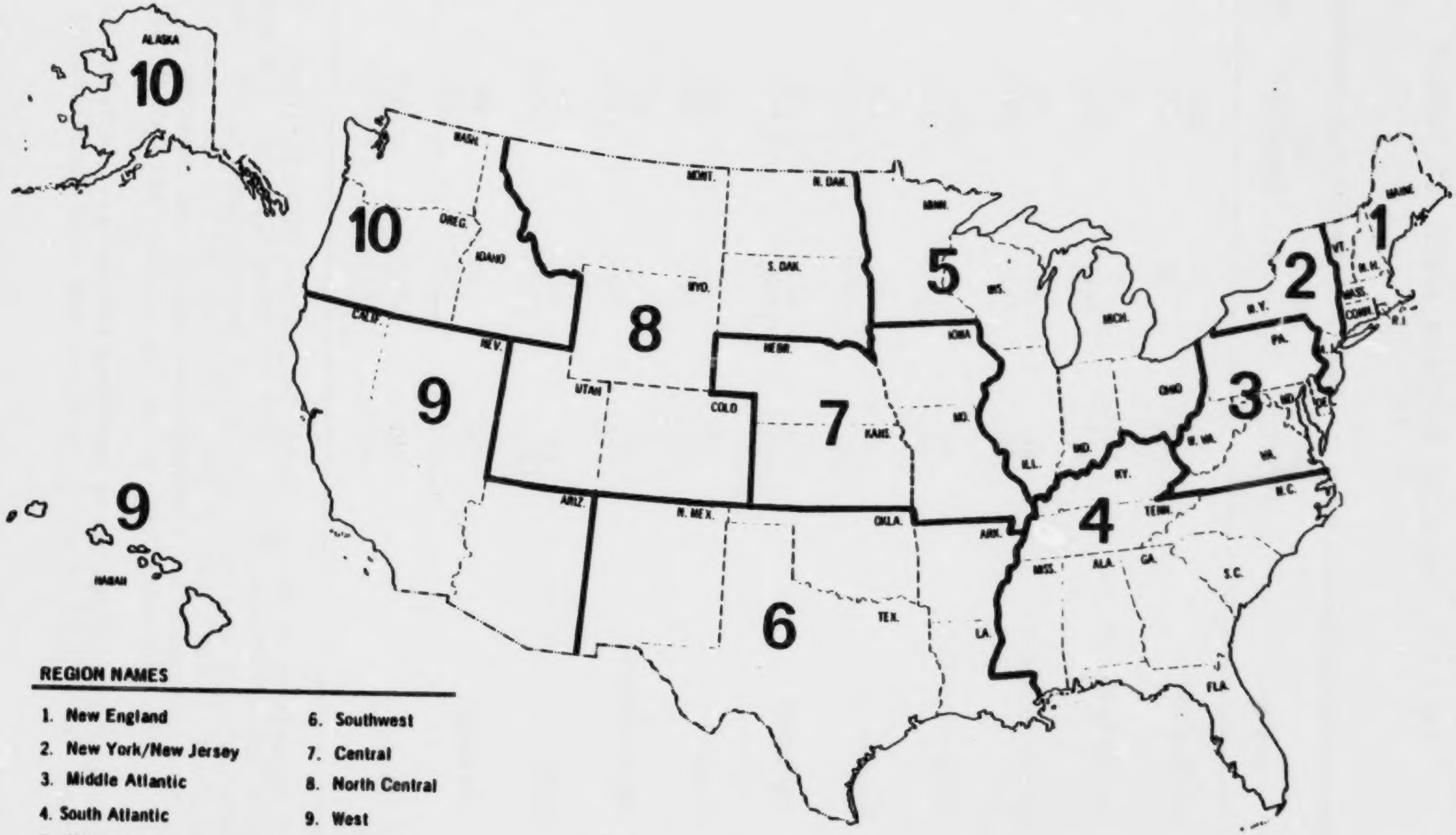
---

[a] U.S. Department of Energy, Energy Information Administration. 1982 Annual Energy Outlook, Middle World Oil Price (Case A). The regional distribution is unofficial and has not been reviewed by EIA. Sum of non-metallurgical coal, natural gas, distillate and residual fuel oil. Excludes petro-chemical feedstocks and natural gas consumed as lease and plant fuels. Includes total boiler and process heat fossil fuel demand.

[b] Excludes fuel consumption in petroleum refineries. Includes construction, mining, agriculture, fishing, forestry, and other manufacturing sectors.

FIGURE 1

Federal Regions of the United States


ALASKA
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HAWAII
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WASH.
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PA.
W. VA.
VA.
MD.
DEL.
3
N.Y.
N.J.
2
MAINE
VT.
N.H.
MASS.
CONN.
R.I.
1

REGION NAMES

1. New England
2. New York/New Jersey
3. Middle Atlantic
4. South Atlantic
5. Midwest
6. Southwest
7. Central
8. North Central
9. West
10. Northwest

- The Energy Tax Act of 1978 (ETA)
- The Economic Recovery Tax Act of 1981 (ERTA)

The ETA provides several tax incentives for the use of coal and alternative fuels. Additional investment tax credits (ITC's) are granted for coal and alternative fuel commercial investments. Under the ETA, ITC's and accelerated depreciation alternatives are denied for oil and gas investments.

The ETA authorizes a 10 percent tax credit (in addition to the standard 10 percent ITC) for coal and alternative fuel investments made between October 1, 1978 and December 31, 1982, including investments in the following:

- Boilers and other combustors that use coal or an alternative fuel
- Equipment to produce alternative fuels
- Pollution control equipment
- Equipment for handling and storage of alternative fuels

Because authorization for the additional ITC expires in 1982, this provision has not been modeled for this analysis of projected new industrial boiler installations from 1986 to 1990.

In IFCAM, these provisions are modeled for the calculation of after-tax boiler and pollution control equipment capital cost cash flows. Investments in new industrial coal-fired boilers receive the standard 10 percent ITC and qualify for an accelerated depreciation method, whereas no ITC's and straight line depreciation are calculated for new industrial oil-and gas-fired boiler investments.

The ERTA revises the depreciation schedules for captial investment and thus improves the tax incentives for new industrial boilers. The depreciation period for new coal-, oil-, and natural gas-fired industrial boilers is reduced to five years.

The Tax Equity and Fiscal Responsibility Act (TEFRA) of 1982 revised the Accelerated Cost Recovery System (ACRS) annual recovery percentages for five-year period recovery property acquired after 1985. TEFRA also reduced the basis for depreciation by 50 percent of the ITC taken when the regular ITC (10 percent for five-year recovery period property placed in service after 1980) is selected. These TEFRA Federal tax code revisions are not reflected in this analysis. They do not apply to new industrial oil and gas boiler investments because they are not permitted to be depreciated using the ACRS accelerated depreciation schedule and they do not qualify for the ITC. The TEFRA Federal tax code revisions do apply to new industrial coal boiler investments, but they are not expected to significantly alter the projected impacts of the alternative NSPS which are presented in Sections 3 and 4 of this report.

In addition, provisions of the Powerplant and Industrial Fuel Use Act of 1978, which prohibit the use of oil or natural gas in large new industrial boilers, are an available feature in IFCAM but currently are not utilized in the analysis of the potential impacts of the recommended NSPS.

2.2.3 Fuel Price Forecasts

Fuel choice decisions in IFCAM are based on selecting the alternative with the lowest total after-tax net present value of capital, annual O&M and fuel expenses over a 15-year period. In this analysis, the fuel expenses are estimated based on projected regional delivered fuel prices from 1987 to the year 2001.

Naturally there is uncertainty related to energy market conditions over the next fifteen years. Two regional forecasts of industrial residual fuel oil and natural gas prices were developed in order to evaluate the sensitivity of IFCAM results (projected impacts of alternative NSPS) to this key exogenous assumption, industrial fuel price differences.

Table 2-3 presents the two world oil price forecasts. Both forecasts are based on DOE's (Office of Policy, Planning and Analysis) WOIL forecasting model. EEA estimated regional industrial residual fuel oil and natural gas prices for both world oil price projections.[4] These forecasts are presented in Appendices B and C. Distillate fuel oil price forecasts were not prepared because it is expected that natural gas prices will remain lower than distillate fuel oil prices and, therefore, natural gas (or residual fuel oil) will be a lower cost new industrial boiler fuel type.

Only one set of projected industrial coal prices were used in this analysis. Therefore, the two fuel price scenarios have different projected industrial residual fuel oil and natural gas prices but identical projected industrial coal prices.

TABLE 2-3. WORLD OIL PRICE FORECASTS[a]
(1982 $/bbl)

Year	Reference price scenario[b]	Higher oil and gas prices scenario[c]
1985	25.00	25.90
1990	28.00	31.90
1995	32.00	46.50
2000	37.00	57.40

[a] Average refiner acquisition cost of imported crude oil.

[b] Energy and Environmental Analysis, Inc.

[c] Case B of the fourth National Energy Policy Plan (NEPP-IV or NEPP-1983). Energy Projections to the Year 2010. U.S. Department of Energy, Office of Policy, Planning and Analysis. DOE/PE-0029/2. October 1983.

The industrial coal types in IFCAM have been defined by ICF Incorporated in terms of coal type (bituminous or subbituminous) and sulfur, ash, and Btu content. There are up to nine distinct coal types per region in IFCAM: 6 sulfur classes for bituminous coals and 3 sulfur classes for subbituminous coals. The tables in Appendices D and E summarize the key characteristics and projected prices for the industrial coal types in IFCAM.

2.2.4 Environmental Policies

Environmental policies embodied in the 1970 Clean Air Act (CAA) and the subsequent 1977 amendments define the regulatory context for this analysis. The Act gave the EPA the authority to establish National Ambient Air Quality Standards (NAAQS) that would protect the health and welfare of the population. There are currently NAAQS for six "criteria pollutants": sulfur oxides, PM, NO_x, lead, carbon monoxide (CO), and ozone. Industrial sources are subject to two classes of environmental regulations adopted to ensure compliance with ambient air standards: State Implementation Plan (SIP's) and Nonattainment (NA)/Prevention of Significant Deterioration (PSD). The CAA gave the EPA the authority to promulgate NSPS regulations governing the emissions of pollutants from specific categories of newly constructed sources. Each new source must meet requirements of all of these programs.

For purposes of this analysis, no attempt was made to predict the impact of NA, PSD, or local regulations not part of SIP's. Therefore, each new boiler is assumed to be subject to a SIP or NSPS, whichever may be more stringent. The SIP's in IFCAM are characteristic of those regulations for existing industrial fossil fuel-fired boilers.

The CAA stipulates that each State must prepare a SIP that provides for the implementation, maintenance, and enforcement of the NAAQS within its geographic area. SIP's vary substantially among States, both in the severity of the standards and the way they are expressed. States specify standards in a variety of forms including pounds of pollutant per energy content of the fuel (lb/MMBtu), pounds of pollutant emitted per 1,000 pounds of steam, or pollutant content of the fuel, by weight, in percentage terms. In many States, SIP requirements also vary by fuel type and boiler size.

A set of SIP regulations reflecting the regional diversity of air emission limits has been compiled for use in IFCAM. These SIP's are identified by pollutant, fuel type, boiler size, and AQCR and are converted to pounds of pollutant per million Btu.

The SIP file is current as of July 1980 for particulate matter and nitrogen oxide emission standards. The SIP file has been updated to March 1983 for SO_2 emission regulations.

The CAA requires that SIP's include provisions designed to upgrade areas of air quality not in attainment with NAAQS. To the extent that NA provisions are reflected in the SIP's, NA-related SIP revisions are incorporated into the IFCAM SIP file.

PSD requires that States maintain the air quality of their areas attaining NAAQS. Each PSD area is subject to provisions of one of three PSD classes that specify allowable incremental increases in ambient air pollutant concentrations. Construction of individual stationary sources is reviewed to ensure that expected emissions from these new facilities will not increase an area's ambient air pollution concentration greater than allowed increments such that it exceeds the NAAQS. Because PSD provisions are applied by States to individual facilities on a case-by-case or site-specific basis, PSD has not been modeled.

Because only a limited number of NA SIP revisions are modeled in IFCAM, and PSD regulations have not been addressed, the stringency of local regulations may be understated. Consequently, the impact of the alternative emission regulations may be overstated because a number of boilers may be subject to more stringent local regulations than are reflected in IFCAM.

2.3 EVALUATION CRITERIA

Throughout the development of alternative emission regulations for new industrial boilers, a set of key output parameters has been considered to be particularly useful in comparing projected aggregate impacts of alternative regulations. This set of criteria includes the following three parameters:

- Level of emissions
- Cost of generating steam
- Coal and residual fuel oil demand

These criteria are used to evaluate impacts of the alternative standards for distinct boiler size classes and are described in this section.

The level of SO_2 emissions projected under alternative regulations is a primary criterion by which to evaluate these regulations. The level of emissions is a function of both the regulatory scenario and the mix of fuels demanded.

In addition, the effect of alternative regulations on the total expected cost of generating steam in new industrial boilers is evaluated. Steam costs include capital and operating costs for the boiler, capital and operating costs for any required pollution control equipment, and fuel costs. The cost impact of the alternative standards is the change from the base case in the total cost of generating steam. For this analysis, aggregate costs for the least-cost fuel types are presented on a before-tax annualized basis using a 10 percent discount rate and a 15-year investment period.

Coal penetration is projected coal demand expressed as a percentage of total projected fossil fuel demand (coal, fuel oil, and natural gas) for new industrial boilers. The impact of alternative standards on coal penetration is then examined. The potential for increased coal use in the industrial sector is partly a function of environmental regulations applicable to industrial facilities. In particular, air emission regulations can increase significantly the cost of burning coal compared to the alternative of burning a relatively clean type of fossil fuel such as natural gas.

The potential for increased residual fuel oil combustion in the industrial sector is also partly a function of environmental regulations. Proposed air emission standards may affect projected residual fuel oil demand in new industrial boilers.

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3. PROJECTED IMPACTS OF ALTERNATIVE SO_2 EMISSIONS STANDARDS

This section describes the regulatory baseline NSPS air emissions standards and alternative SO_2 emissions regulations for new industrial fossil fuel-fired boilers. Projected emissions, cost and energy demand effects of the alternative standards, relative to the regulatory baseline, are summarized.

3.1 REGULATORY BASELINE AND ALTERNATIVE SO_2 EMISSIONS STANDARDS

The regulatory baseline is represented by current and proposed air emissions standards: the current SO_2 NSPS, the proposed PM and NO_x NSPS and current SIP's. Table 3-1 presents the current SO_2 NSPS and the proposed PM NSPS. New industrial boilers are assumed to be subject to a SIP if the SIP is more stringent than the applicable NSPS shown in this table.

All new industrial oil- and gas-fired and spreader stoker coal-fired boilers larger than 29 MW (100 MMBtu/hr) are assumed to employ low excess air to control NO_x emissions. If the residual fuel oil burned in the new large industrial boiler has a nitrogen content greater than 0.35 percent, staged combustion air is required to control NO_x emissions. All new pulverized coal-fired industrial boilers larger than 29 MW (100 MMBtu/hr) require staged combustion air to control NO_x emissions. These assumptions for new large industrial residual fuel oil and coal boilers are consistent with the proposed NO_x NSPS (49 FR 25103).

The proposed NO_x NSPS for new large industrial natural gas and distillate fuel oil boilers is based on the low NO_x burner technology, not a current pollution control option in IFCAM. This difference in assumptions will not significantly affect the expected impacts of alternative SO_2 NSPS for new industrial coal and residual fuel oil boilers.

The alternative SO_2 emissions standards are presented in Table 3-2. These alternatives are applicable for new industrial residual fuel oil and coal boilers larger than 29 MW (100 MMBtu/hr). The applicable regulation

TABLE 3-1. REGULATORY BASELINE NSPS ASSUMPTIONS
ng/J (lb/MMBtu)

Fuel type	Boiler size category MW (MMBtu/hr)		SO_2	PM
Natural gas	<73	(<250)	--	--
	>73	(>250)	--	43 (0.1)[a]
Distillate fuel oil	<73	(<250)	--	--
	>73	(>250)	340 (0.8)[a]	43 (0.1)[a]
Residual fuel oil	<73	(<250)	SIP	SIP
	>73	(>250)	340 (0.8)[a]	43 (0.1)[a]
Coal	<29	(<100)	SIP	SIP
	29-73	(100-250)	SIP	22 (0.05)[b,c]
	>73	(>250)	520 (1.2)[a,d]	22 (0.05)[b]

[a] Current NSPS (40 CFR Part 60, Subpart D for fossil fuel-fired steam generators).

[b] Proposed NSPS (49 FR 25103).

[c] 86 ng/J (0.20 lb/MMBtu) if the annual capacity utilization rate is less than 30 percent.

[d] 30-day rolling average.

TABLE 3-2. ALTERNATIVE SO_2 NSPS EMISSIONS STANDARDS FOR NEW INDUSTRIAL FOSSIL FUEL-FIRED BOILERS

		Residual fuel oil		Coal	
Alternative control level	Boiler size category MW (MMBtu/hr)	Ceiling ng/J (lb/MMBtu)	Required percentage reduction	Ceiling[a] ng/J (lb/MMBtu)	Required percentage reduction
Baseline	29-73 (100-250)	--	--	--	--
	>73 (>250)	340 (0.8)	--	520 (1.2)	--
I	29-73 (100-250)	690 (1.6)	--	730 (1.7)	--
	>73 (>250)	340 (0.8)	--	520 (1.2)	--
II	>29 (>100)	340 (0.8)	--	520 (1.2)	--
III	>29 (>100)	340 (0.8)	--	390 (0.9)	≥ 50[b]
IV	>29 (>100)	130 (0.3)	--	260 (0.6)	≥ 50[b]
V	>29 (>100)	340 (0.8)	--[c,d]	520 (1.2)	70-90[b,d]
VI	>29 (>100)	130 (0.3)	90[b]	260 (0.6)	90[b]

[a] 30-day rolling average.

[b] Scrubbing is required.

[c] Scrubbing is not required if the uncontrolled emission rate is equal to or less than 130 ng SO_2/J (0.3 lb SO_2/MMBtu). If the uncontrolled emission rate is greater than 130 ng SO_2/J (0.3 lb SO_2/MMBtu), 70-90 percent SO_2 emissions reduction is required.

[d] The floor emissions rate is 260 ng SO_2/J (0.6 lb SO_2/MMBtu).

is either an emissions ceiling (i.e., alternative control levels I through IV) or a fixed (i.e., alternative control level VI) or variable (i.e., alternative control level V) percentage reduction.

Compliance with the alternative SO_2 NSPS emissions standards is achieved by burning a low sulfur fuel type (with an uncontrolled emission rate equal to or lower than emissions ceiling in Table 3-2) or scrubbing a medium or high sulfur fuel type. When scrubbing, the controlled SO_2 emission rate must remain lower than the ceiling presented in Table 3-2.

For alternative control levels III through VI, all coal types must be scrubbed. For alternative control level V, all coal types must be scrubbed with a 90 percent SO_2 emissions removal rate; if the controlled emission rate is lower than 260 ng SO_2/J (0.6 lb SO_2/MMBtu), the percentage reduction rate may be reduced to (but no lower than) 70 percent. Alternative control level V represents the level of control currently required under Subpart Da for new electric utility coal-fired steam generating units.

3.2 PROJECTED NATIONAL IMPACTS OF THE ALTERNATIVE SO_2 EMISSIONS STANDARDS

This section presents IFCAM projections of total SO_2 emissions and fuel demand by fuel type in 1990 from new industrial fossil fuel-fired boilers larger than 29 MW (100 MMBtu/hr) and installed between 1985 and 1990. This section also presents IFCAM projections of total capital and annualized costs for these new industrial boiler investments. IFCAM projections for the regulatory baseline NSPS assumptions are compared with IFCAM forecasts for the alternative SO_2 NSPS emissions standards. Results by boiler size class are presented in Appendix F.

3.2.1 Fuel Demand Impacts

IFCAM projects that 604 new industrial fossil fuel-fired (coal, fuel oil, or natural gas) boilers, each larger than 29 MW (100 MMBtu/hr), will be installed during this period in the United States. They are expected to consume a total of 525 PJ (498 trillion Btu) in 1990. This projected "population" of large new industrial boilers is based on:

- The assumed rate of growth in total industrial fossil fuel demand (see Table 2-2)

- Estimates of how much of this projected increase will be consumed in industrial boilers versus process heaters
- Estimates of the retirements of existing industrial boilers during the 1985-1990 period
- Estimates of the distribution of fuel demand in new large versus small industrial boilers

This forecast of new large industrial fossil fuel-fired boiler installations is held constant in this analysis and is not altered as a function of other input assumptions (e.g., projected oil and gas prices or alternative SO_2 NSPS assumptions).

Table 3-3 presents the projected fossil fuel mix by fuel price scenario, SO_2 NSPS assumption, and fuel type. The fuel mix is not fixed; it is a function of the fuel price scenario, the SO_2 NSPS assumptions, and many other model parameters (i.e., boiler and pollution control equipment cost estimates).

The projected demand for coal in new industrial boilers is very low under the reference price scenario. Coal is not selected because the projected industrial natural gas and residual fuel oil prices are not large enough to offset the relatively high coal capital and annual non-fuel O&M expenses.

The projected coal market share is significantly higher for the higher oil and gas prices scenario. Projected natural gas and residual fuel oil prices are much higher under the higher oil and gas prices scenario than they are under the reference price scenario (reference Appendices B and C). The fuel choice decision criteria in IFCAM for new industrial boilers is based on a comparison of projected after-tax capital, O&M and fuel expenses over a 15-year period. Therefore, higher projected oil and gas prices are expected to increase the projected demand for coal.

In general, coal may be an economical fuel type when the new industrial boiler sizes and/or expected annual capacity utilization rates are large. Coal is never selected in IFCAM as a new industrial boiler fuel type if the expected annual capacity utilization rate is lower than 30 percent. Therefore, the expected annual capacity utilization rate for each new unit is an important factor in the fuel choice decision process in IFCAM.

TABLE 3-3. PROJECTED FUEL DEMAND IN 1990 FOR LARGE NEW INDUSTRIAL FOSSIL FUEL-FIRED BOILERS[a]
PJ (10^{12} Btu)

Fuel price scenario	Alternative control level	Natural gas	Residual fuel oil	Coal
Reference	Baseline	160 (152)	341 (323)	24 (23)
	I	161 (153)	347 (329)	18 (17)
	II	237 (225)	271 (257)	18 (17)
	III	245 (232)	271 (257)	9 (9)
	IV	282 (267)	217 (206)	27 (26)
	V	282 (267)	217 (206)	27 (26)
	VI	310 (294)	188 (178)	27 (26)
Higher Oil and Gas Prices	Baseline	218 (207)	8 (7)	300 (284)
	I	250 (237)	0 (0)	275 (261)
	II	264 (250)	0 (0)	262 (248)
	III	364 (345)	0 (0)	161 (153)
	IV	364 (345)	0 (0)	161 (153)
	V	364 (345)	0 (0)	161 (153)
	VI	370 (351)	0 (0)	155 (147)

[a] Each larger than 29 MW (100 MMBtu/hr) and installed between 1985 and 1990. Total fossil fuel demand in 1990 is 525 PJ (498 trillion Btu).

Another key factor is the location of the new unit. SIP's and projected fuel prices vary by region.

Residual fuel oil demand in new industrial boilers is very small under the higher oil and gas price scenario. In general, the projected natural gas prices are lower than the projected residual fuel oil prices in this scenario (reference Appendix C). As a result, natural gas is a lower cost alternative than residual fuel oil.

Under the reference price scenario, a significant amount of residual fuel oil is projected. In this case, the projected natural gas prices are not lower than the projected residual fuel oil prices (reference Appendix B). They are similar to the projected medium or low sulfur residual fuel oil prices. Since the projected industrial natural gas and residual fuel oil prices are somewhat "competitive" in the reference price scenario, there is a significant amount of natural gas and residual fuel oil demand. The actual projected natural gas/residual fuel oil mix is a function of SIP's and the SO_2 NSPS assumptions for residual fuel oil.

The projected demand for natural gas is higher under the alternative standards than it is under the regulatory baseline in Table 3-3. The alternative SO_2 emissions standards increase the costs of burning residual fuel oil and coal in large new industrial boilers. Some new units (which selected coal or residual fuel oil under the regulatory baseline) select natural gas under the alternative standards as the least-cost alternative.

Under the reference price scenario/regulatory baseline, the new industrial boiler population has selected residual fuel oil as the primary fuel type. Under the higher coal and gas prices/regulatory baseline, the new industrial boiler population has chosen coal as the primary fuel type.

3.2.2 Projected SO_2 Emissions Impacts

Table 3-4 presents the projected SO_2 emissions for the alternative standards. The total projected SO_2 emissions reduction in 1990 is projected to range from 68-281 Gg (75-310 thousand short tons). The total projected SO_2 emissions reductions are relatively large (up to 95 percent).

Some portion of the total projected SO_2 emissions reductions presented in Table 3-4 is due to the fact that the fuel mix is not held constant between the regulatory baseline and the alternative standards. A portion

TABLE 3-4. COMPARISON OF TOTAL PROJECTED SO_2 EMISSIONS IN 1990 FROM NEW LARGE INDUSTRIAL FOSSIL FUEL-FIRED BOILERS[a]
Gg (10^3 short tons)

Alternative control level	Fuel price scenario: Reference	Fuel price scenario: Higher oil and gas prices
Baseline	253 (279)	296 (326)
I	185 (204)	134 (148)
II	96 (106)	103 (114)
III	93 (102)	42 (46)
IV	35 (39)	31 (34)
V	43 (47)	27 (30)
VI	15 (16)	15 (16)

[a] Each larger than 29 MW (100 MMBtu/hr) and installed between 1985 and 1990.

of the new industrial boilers, that select coal or residual fuel oil under the regulatory baseline, choose natural gas under the alternative standards (see Table 3-3).

Compliance fuel types (as opposed to scrubbing non-compliance fuel types) are the primary control strategy selected for the regulatory baseline and alternative control levels I and II. Compliance fuel types are also selected as the primary compliance strategy for new large industrial residual fuel oil boilers for alternative control level III.

Industrial residual fuel oil-fired boilers can burn a very low sulfur fuel type (less than 0.3 percent sulfur) or scrub emissions from the combustion of a medium or high sulfur fuel type under alternative control levels IV and V. Under the reference price scenario/alternative control levels IV and V, 188 new industrial residual fuel oil boilers select scrubbers and 57 new industrial residual fuel oil boilers select a very low sulfur fuel type. In many cases, it is less expensive to scrub a 1.6 percent sulfur residual fuel oil than it is to burn a very low sulfur fuel type. This occurs because the projected residual fuel oil sulfur premiums (0.3 percent sulfur residual fuel oil price less the 1.6 percent sulfur residual fuel oil price) are larger than the annualized scrubber capital and O&M costs. Scrubbers are not selected on all new industrial residual fuel oil boilers under the alternative control levels IV and V because scrubbers are not an economical compliance alternative for new units with low annual capacity utilization rates.

Sodium scrubbers are the only FGD technology selected in IFCAM. Lime spray drying and dual alkali FGD technologies are options in IFCAM which are not selected because they are more expensive than sodium scrubbing systems.

The projected SO_2 emissions reductions presented in Table 3-4 are due to scrubbing, switching to lower sulfur coal or residual fuel oil types, and to switching from coal or residual fuel oil combustion under the regulatory baseline to natural gas combustion under the alternative control level. Accordingly, the average cost-effectiveness of SO_2 emissions control on large new industrial fossil fuel-fired boilers (derived from these aggregate IFCAM projections) reflect several types of pollution control strategies and do not match estimates of the average cost-effectiveness of any single technology.

3.2.3 Projected Cost Impacts

The projected increase in total annualized costs is projected to range from $8 million to $133 million (reference Table 3-5). The total annualized cost increases are larger for the reference price scenario than for the higher oil and gas prices scenario for two reasons:

- There is more total demand for residual fuel oil and coal in the reference price scenario/regulatory baseline (365 trillion Btu) than under the higher oil and gas prices/regulatory baseline (307 trillion Btu).
- A significant number of new industrial coal-fired boilers under the higher oil and gas prices/regulatory baseline choose natural gas under the alternative standards (see Table 3-3). This type of "switching" from a capital- and annual non-fuel O&M-intensive investment (coal) to a fuel cost-intensive alternative (natural gas) can result in small (or sometimes negative) increases in total before-tax annualized costs.* If the fuel mix was held constant (that is, if the fuel mix under the higher oil and gas prices/alternative standards was identical to the fuel mix under the higher oil and gas prices/regulatory baseline), then the range of the total projected annualized cost increase under the higher oil and gas prices scenario would be significantly higher than $10-33 million.

Table 3-5 shows that the total projected capital costs are much higher under the higher oil and gas prices scenario than under the reference price scenario. This is because coal is a capital-intensive investment and the projected coal demand is much higher under the higher oil and gas

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*Recall that IFCAM makes fuel choice decisions based on a comparison of after-tax costs.

TABLE 3-5. COMPARISON OF PROJECTED COSTS[a]
(millions of 1982 dollars)

Alternative control level	Fuel price scenario	
	Reference	Higher oil and gas prices
Total annualized costs[b,c]		
Baseline	3,349	3,725
I	3,357	3,735
II	3,406	3,743
III	3,408	3,754
IV	3,476	3,757
V	3,474	3,758
VI	3,482	3,757
Increase in total annualized costs over the Baseline		
I	8	10
II	57	18
III	59	29
IV	127	32
V	125	33
VI	133	32
Total capital costs[c]		
Baseline	2,588	5,925
I	2,468	5,562
II	2,479	5,350
III	2,391	4,077
IV	2,649	4,066
V	2,652	4,078
VI	2,653	3,986

[a] New industrial fossil fuel-fired boilers larger than 29 MW (100 MMBtu/hr) and installed between 1985 and 1990.

[b] Capital costs x 0.13147 (a capital recovery factor based on a 10 percent interest rate and a 15-year period) plus annual non-fuel O&M costs plus levelized fuel costs.

[c] Includes total boiler and pollution control equipment expenses.

prices scenario than under the reference price scenario. Total projected capital costs are lower under most of the alternative standards than under the regulatory baseline because the projected coal demand in new industrial boilers is lower under the alternative standards than under the regulatory baseline (see Table 3-3).

3.2.4 Other Impacts

Sodium scrubbing is the only FGD technology selected in IFCAM. It generates a liquid effluent. Table 3-6 indicates that the projected increase in liquid waste due to the alternative standards is as large as 5.4 million cubic meters.

The projected solid waste disposal requirements are larger under the higher oil and gas prices scenario because there is a much larger demand for coal in this case versus the base case fuel prices. Under the higher oil and gas prices scenario, the projected total solid waste disposal requirements drop due to the alternative standards because total projected coal demand declines (see Table 3-3).

3.3 PROJECTED REGIONAL SO_2 EMISSIONS FORECASTS

IFCAM projects regional large new industrial fossil fuel-fired boiler SO_2 emissions. Figure 1 presents the ten Federal regions.

Tables 3-7 through 3-12 present the regional SO_2 emissions forecasts for the regulatory baseline and the six alternative control levels. Most of the projected SO_2 emissions reductions are located in Federal regions 4, 5, and 6.

TABLE 3-6. PROJECTED SOLID AND LIQUID WASTE DISPOSAL REQUIREMENTS

Alternative control level	Coal boiler solid waste[a] Gg (10^3 short tons)	Scrubber liquid waste[b] 10^3 cubic meters
Reference fuel prices		
Baseline	97 (107)	811
I	66 (73)	732
II	69 (76)	1,154
III	38 (42)	1,262
IV	115 (127)	4,409
V	115 (127)	4,205
VI	115 (127)	4,944
Higher oil and gas prices		
Baseline	1,228 (1,345)	667
I	1,111 (1,225)	699
II	1,046 (1,153)	826
III	701 (773)	5,584
IV	681 (751)	5,719
V	701 (773)	6,080
VI	651 (718)	6,062

[a] New industrial coal-fired boilers installed between 1986 and 1990 which are larger than 29 MW (100 MMBtu/hr). Includes coal boiler bottom ash and fly ash collected by particulate matter emissions control equipment.

[b] New industrial coal and residual fuel oil boilers installed between 1986 and 1990 which are larger than 29 MW (100 MMBtu/hr). Includes sodium scrubbing treated effluent.

TABLE 3-7. PROJECTED REGIONAL SO_2 EMISSIONS IN 1990[a]
Gg (10^3 short tons)

		Reference price scenario					
		Regulatory baseline		Alternative control level			
	Federal region			I		II	
1.	New England	2.8	(3.1)	2.8	(3.1)	2.4	(2.7)
2.	New York/New Jersey	4.6	(5.1)	4.4	(4.8)	3.7	(4.1)
3.	Middle Atlantic	19.1	(21.0)	18.1	(20.0)	12.9	(14.2)
4.	South Atlantic	48.4	(53.3)	37.2	(41.0)	24.9	(27.4)
5.	Midwest	58.2	(64.1)	43.7	(48.2)	29.8	(32.9)
6.	Southwest	77.1	(85.0)	44.6	(49.2)	b	b
7.	Central	17.1	(18.9)	12.0	(13.2)	1.7	(1.9)
8.	North Central	7.4	(8.2)	5.4	(6.0)	3.5	(3.9)
9.	West	6.6	(7.3)	6.2	(6.8)	5.4	(6.0)
10.	Northwest	12.1	(13.3)	11.6	(12.8)	11.4	(12.6)
	U.S.	253.5	(279.4)	186.1	(205.1)	95.9	(105.8)

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990 and larger than 29 MW (100 MMBtu/hr).

[b] Less than 50 Mg (55 short tons). The projected SO_2 emission reduction is 99 percent because natural gas is the only fuel type selected in this region under alternative control level II.

TABLE 3-8. PROJECTED REGIONAL SO_2 EMISSIONS IN 1990[a]
Gg (10^3 short tons)

		Reference price scenario					
		Regulatory baseline		Alternative control level			
	Federal region			III		IV	
1.	New England	2.8	(3.1)	2.4	(2.7)	0.8	(0.9)
2.	New York/New Jersey	4.6	(5.1)	3.7	(4.1)	1.6	(1.8)
3.	Middle Atlantic	19.1	(21.0)	12.9	(14.2)	5.3	(5.8)
4.	South Atlantic	48.4	(53.3)	24.9	(27.4)	9.9	(10.9)
5.	Midwest	58.2	(64.1)	29.8	(32.9)	9.1	(10.0)
6.	Southwest	77.1	(85.0)	b	b	b	b
7.	Central	17.1	(18.9)	b	b	b	b
8.	North Central	7.4	(8.2)	1.5	(1.6)	0.8	(0.9)
9.	West	6.6	(7.3)	5.4	(6.0)	2.6	(2.9)
10.	Northwest	12.1	(13.3)	11.4	(12.6)	5.0	(5.5)
	U.S.	253.5	(279.4)	92.2	(101.7)	35.1	(38.7)

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990 and larger than 29 MW (100 MMBtu/hr).

[b] Less than 50 Mg (55 short tons). The projected SO_2 emission reduction is 99 percent because natural gas is the only fuel type selected in this region under alternative control levels III and IV.

TABLE 3-9. PROJECTED REGIONAL SO_2 EMISSIONS IN 1990[a] Gg (10^3 short tons)

		Reference price scenario					
				Alternative control level			
	Federal region	Regulatory baseline		V		VI	
1.	New England	2.8	(3.1)	0.9	(1.0)	0.2	(0.2)
2.	New York/New Jersey	4.6	(5.1)	1.7	(1.9)	0.5	(0.6)
3.	Middle Atlantic	19.1	(21.0)	6.7	(7.4)	2.6	(2.9)
4.	South Atlantic	48.4	(53.3)	10.9	(12.0)	3.3	(3.6)
5.	Midwest	58.2	(64.1)	12.1	(13.3)	5.3	(5.8)
6.	Southwest	77.1	(85.0)	b	b	b	b
7.	Central	17.1	(18.9)	b	b	b	b
8.	North Central	7.4	(8.2)	0.8	(0.9)	0.3	(0.3)
9.	West	6.6	(7.3)	3.4	(3.8)	0.8	(0.9)
10.	Northwest	12.1	(13.3)	6.1	(6.7)	1.7	(1.9)
	U.S.	253.5	(279.4)	42.7	(47.1)	14.8	(16.3)

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990 and larger than 29 MW (100 MMBtu/hr).

[b] Less than 50 Mg (55 short tons). The projected SO_2 emission reduction is 99 percent because natural gas is the only fuel type selected in this region under alternative control levels V and VI.

TABLE 3-10. PROJECTED REGIONAL SO_2 EMISSIONS IN 1990[a]
Gg (10^3 short tons)

	Higher oil and gas prices					
			Alternative control level			
Federal region	Regulatory baseline		I		II	
1. New England	b	b	b	b	b	b
2. New York/New Jersey	5.2	(5.7)	2.0	(2.2)	1.8	(2.0)
3. Middle Atlantic	25.4	(28.0)	15.8	(17.4)	11.2	(12.4)
4. South Atlantic	73.5	(81.0)	32.4	(35.7)	23.5	(25.9)
5. Midwest	74.1	(81.7)	32.3	(35.6)	22.8	(25.1)
6. Southwest	70.7	(77.9)	27.9	(30.8)	25.6	(28.2)
7. Central	22.9	(25.2)	4.1	(4.5)	3.4	(3.7)
8. North Central	13.3	(14.7)	10.8	(11.9)	8.7	(9.6)
9. West	2.8	(3.1)	2.8	(3.1)	2.8	(3.1)
10. Northwest	7.8	(8.6)	5.8	(6.4)	3.8	(4.2)
U.S.	295.7	(325.9)	133.9	(147.6)	103.7	(114.3)

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990 and larger than 29 MW (100 MMBtu/hr).

[b] Less than 50 Mg (55 short tons).

TABLE 3-11. PROJECTED REGIONAL SO_2 EMISSIONS IN 1990[a]
Gg (10^3 short tons)

		Higher oil and gas prices					
				Alternative control level			
	Federal region	Regulatory baseline		III		IV	
1.	New England	b	b	b	b	b	b
2.	New York/New Jersey	5.2	(5.7)	1.2	(1.3)	0.8	(0.9)
3.	Middle Atlantic	25.4	(28.0)	7.3	(8.1)	5.1	(5.6)
4.	South Atlantic	73.5	(81.0)	7.2	(7.9)	6.2	(6.8)
5.	Midwest	74.1	(81.7)	10.8	(11.9)	7.3	(8.0)
6.	Southwest	70.7	(77.9)	6.9	(7.6)	6.0	(6.6)
7.	Central	22.9	(25.2)	1.2	(1.3)	0.7	(0.8)
8.	North Central	13.3	(14.7)	2.4	(2.7)	1.6	(1.8)
9.	West	2.8	(3.1)	0.6	(0.7)	0.5	(0.5)
10.	Northwest	7.8	(8.6)	3.7	(4.1)	2.4	(2.7)
	U.S.	295.7	(325.9)	41.4	(45.6)	30.6	(33.7)

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990 and larger than 29 MW (100 MMBtu/hr).

[b] Less than 50 Mg (55 short tons).

TABLE 3-12. PROJECTED REGIONAL SO_2 EMISSIONS IN 1990[a]
Gg (10^3 short tons)

	Higher oil and gas prices					
			Alternative control level			
Federal region	Regulatory baseline		V		VI	
1. New England	b	b	b	b	b	b
2. New York/New Jersey	5.2	(5.7)	0.8	(0.9)	0.5	(0.6)
3. Middle Atlantic	25.4	(28.0)	5.1	(5.6)	3.4	(3.8)
4. South Atlantic	73.5	(81.0)	4.4	(4.8)	1.5	(1.6)
5. Midwest	74.1	(81.7)	7.3	(8.0)	6.7	(7.4)
6. Southwest	70.7	(77.9)	4.2	(4.6)	1.0	(1.1)
7. Central	22.9	(25.2)	0.8	(0.9)	0.1	(0.1)
8. North Central	13.3	(14.7)	1.6	(1.8)	0.5	(0.6)
9. West	2.8	(3.1)	0.5	(0.5)	0.2	(0.2)
10. Northwest	7.8	(8.6)	2.4	(2.7)	0.5	(0.5)
U.S.	295.7	(325.9)	26.9	(29.7)	14.5	(16.0)

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990 and larger than 29 MW (100 MMBtu/hr).

[b] Less than 50 Mg (55 short tons).

4. ECONOMIC IMPACTS

4.1 INTRODUCTION

This section presents economic impacts for one of the alternative SO_2 emission standards for new industrial fossil fuel-fired boilers. The alternative control level selected reflects an upper bound on the stringency of emission standards which have been studied by EPA. SO_2 alternative control level VI (reference Table 3-2) requires scrubbing on all new industrial residual fuel oil and coal boilers with a heat input capacity larger than 29 MW (100 MMBtu/hr).

In determining if potentially severe economic impacts could occur to industrial users of steam, the impact analysis examines both cost-related impacts and capital availability issues. Cost related impacts include impacts on product price, value added, and return on assets for selected industries. Capital availability issues refer to the ability of a firm to obtain capital to finance the costs of control required by an alternative SO_2 standard.

A detailed description of the methodology and background information used in the impact analysis is contained in the draft EIS Fossil Fuel-Fired Industrial Boilers - Background Information, Volume 1, (EPA-450/3-82-006a) published in March, 1982. The following discussion presents a summary of the analytical framework and industry profiles included in the draft EIS document. The impact results have been revised to reflect the current national cost impacts generated by EEA's Industrial Fuel Choice Analysis Model (IFCAM).

Because the number of industries that could be affected by the proposed standard is large, a two-fold approach has been used to assess the level and nature of the economic impact without undertaking a detailed analysis of every industry. The first component is performed on the general industry level (i.e., food or steel industries) for major steam-using industries. Eight industry groups, which account for approximately 70 percent of total industrial steam consumption are examined.

The second component of the user impact analysis focuses on the economic impact of selected four-digit Standard Industrial Classification (SIC) industries. This focus is necessary since the major steam user analysis utilizes industry averages to assess economic impact. Because each two-digit SIC industry grouping is composed of many four-digit SIC industries, the industry average may not capture the impact of regulatory options on specific four-digit SIC industries. In addition, four-digit SIC industries that are not part of the eight industry groups analyzed under major steam users may be affected severely. To remedy the situation, the economic impact on selected four-digit SIC industries is examined. The industries chosen for this component of the analysis were selected by a screening process designed to identify the four-digit SIC industries most likely to experience adverse economic impacts. By evaluating the economic impact on industries most likely to be affected adversely, the impact on other industries groups can be inferred to be less severe.

The remainder of this section is divided into two parts. Section 4.2 presents an overview of the profiles for industries that will be covered in the economic impact analysis. Section 4.3 covers the results of the impact analysis.

4.2 INDUSTRY ECONOMIC PROFILES

4.2.1 Major Steam Users Profile

The major steam users consist of the following eight industry groups:

- Food
- Textiles
- Paper
- Chemicals
- Petroleum refining
- Stone, clay, and glass
- Steel
- Aluminum.

These industries are examined because together they will bear most of the cost burden of an alternative SO_2 standard. Except for steel and aluminum, the industries examined are identified by a two-digit SIC code.

These eight industries generally use approximately 50 percent or more of their energy consumption to generate steam and/or have steam costs that comprise a major percentage of production costs. Table 4-1 shows 1976 total fossil fuel consumption (excluding raw material and feedstock uses) and the percent of total consumption accounted for by boilers in each of the major steam user groups. Approximately 48 percent of all industrial non-feedstock fossil fuel consumption in 1976 was in boilers. The paper, food, and textiles industries consumed significantly more of their fossil fuel in boilers than in other uses; the paper industry consumed approximately 87 percent of its fossil fuel in boilers, the food industry 83 percent, while the textile industry used 80 percent. The chemicals and aluminum industries also were well above the average for industrial boiler fossil fuel consumption.

4.2.2 Selected Industries Profile

This section contains profiles of the seven four-digit SIC industries selected for analysis. Due to the large number of four-digit SIC industries, screening criteria were used to target those industries most likely to experience cost-related impacts and/or capital availability constraints.

Industries most likely to experience cost-related impacts are those with a high steam cost to production cost ratio. A high ratio usually stems from one of two factors: 1) the production process is steam-intensive or 2) the firm or industry has cyclic steam requirements, resulting in a low capacity utilization of the boiler equipment. Low capacity utilization causes the capital cost component of steam costs to rise, yielding high annualized costs per unit of steam. Therefore, capacity utilization and percentage of steam costs to total product costs are used as selection criteria.

Capital availability constraints occur when the cost of acquiring funds is so high that a firm considers a project to be uneconomic or financially unattractive. Capital availability is most often a problem for relatively small firms. Although some large firms may have excessive debt burdens, lack of access to organized capital markets is more often characteristic of small firms. Thus, size is used to identify firms with potential capital availability problems.

TABLE 4-1. FOSSIL FUEL CONSUMPTION CHARACTERISTICS OF THE MAJOR STEAM USERS

SIC Code	Industry	Total fossil fuel consumption[a,b] 10^{12} kJ	Total fossil fuel consumption[a,b] (10^{12} Btu)	Industrial boiler[a] fossil fuel consumption as a percent of total fossil fuel consumption
20	Food	797.8	(756.3)	83
22	Textiles	224.9	(213.2)	81
26	Paper	1,191.9	(1,129.9)	87
28	Chemicals	2,537.2	(2,405.3)	66
29	Petroleum Refineries	1,395.3	(1,322.7)	26
32	Stone, clay and glass	1,128.8	(1,070.1)	4
3312 3315-17	Steel	967.4	(917.1)	30
3334, 3353-55	Aluminum	275.4	(261.1)	64
	Other[c]	2,476.1	(2,347.3)	32
	Total	10,994.7	(10,423.0)	48

[a] Energy and Environmental analysis, Inc. The Industrial Sector Energy Consumption Data Base (ECDB) for 1975 and 1976. December 15, 1980.

[b] Excludes raw materials, feedstock, and use in vehicles. Includes coal, distillate and residual fuel oil, and natural gas.

[c] Includes agriculture, mining, miscellaneous manufacturing, and construction industries.

The following six four-digit SIC industries have been selected for the economic impact analysis and are briefly described in this section.

- Beet sugar refining
- Rubber reclaiming
- Automobile manufacturing
- Petroleum refining
- Iron and steel manufacturing
- Liquor distilling

The fruit and vegetable canning industry, initially profiled for potential economic impacts, has not been included in this report because it is anticipated that its new steam generating equipment would burn natural gas as the primary fuel type and not be affected by an alternative SO_2 NSPS standard.

Beet Sugar Refining Industry: The U.S. beet sugar refining industry (SIC 2063) is characterized by relatively few producers. As of mid-1982, 10 companies operated 40 plants generally located in the midwestern and Pacific States.

Refining operations are highly seasonal, usually commencing in mid-September and ending by mid- to late March. The length of the refining season varies from 120 to 220 days, depending on beet crop conditions. During the average refining season of 180 days, plants operate seven days a week, 24 hours a day. Annual capacity utilization of boilers at a plant is typically in the range of 30 to 45 percent.

In recent years, the annual total output of the beet sugar industry has been decreasing. The number of plants in the industry also has decreased; firms have closed less profitable plants, run operations as a cooperative (i.e., where the firm is owned by the sugar beet farmers) or, as a last resort, entirely terminated operations. The major explanation for decreased production is the increasing level of cane sugar imports and the use of concentrated fructose as a substitute for sugar.

Due to declining sales, most domestic producers are not considering expansion. Instead, they are focusing on plant (and boiler) maintenance and/or replacements as well as company consolidations when economically practical. Due to the industry's small profit margin, only the larger, more profitable firms that benefit from economies of scale would consider investing in a boiler replacement.

Rubber Reclaiming Industry: The rubber reclaiming industry (SIC 3031) consists of eight producers operating eight manufacturing establishments. Although the bulk of reclaiming occurs in Ohio, manufacturing plants are located throughout the eastern States.

Rubber reclaimers buy old rubber tires, inner tubes, and other scrap rubber materials and recycle them into a reusable form of rubber, notably tires and floor mats. Approximately 60 percent of all reclaimed rubber is used in tire manufacturing. For several manufacturers, unmolded reclaimed rubber is the sole output, while for others, especially the larger integrated firms, unmolded recycled rubber is not a primary product but part of an internal subprocess producing various rubber goods.

For the past decade, the rubber reclaiming industry has suffered from volatile sales, production fall-offs, and plant reductions. A series of external factors account for these conditions. Most stringent ceilings on the amounts of reclaimed rubber allowed in car tires have been the largest obstacle to the industry's expansion. With the increasing popularity of radial tires, which contain a much smaller percent of reclaimed rubber than standard ply tires, reclaimed rubber consumption has decreased.

With production dropping, selling prices fluctuating, and production costs mounting, the industry is not considering expanding productive capacity, but instead is using available funds to replace existing capital assets.

Automobile Manufacturing Industry: The U.S. automobile manufacturing industry (SICs 3711, 3713, and 3714) consists of four firms engaged in manufacturing and assembling "American-made" vehicles. These vehicles are produced in many States (and sometimes in other countries), with the majority of production occurring in Michigan, Missouri, Ohio, California, New Jersey, and Wisconsin. In addition to producing automobiles, the four manufacturing firms produce light trucks, commercial trucks, buses, and other motor vehicles.

Except for the industry leader, the market shares of domestic manufacturers declined between 1978 and 1983 due to the increased market share of the dominant domestic producer as well as the increased sales of imported automobiles. The share of total sales accounted for by imports increased by about one-third between 1977 and 1984, from 18.3 percent to 23.5 percent.

Petroleum Refining Industry: The petroleum refining industry (SIC 2911) consists of 153 companies operating 289 domestic refineries. Of these firms, 19 control over 70 percent of the U.S. refining capacity.

Although refineries operate in 41 States, approximately 27 percent of the crude distillation capacity is concentrated in Texas. California and Louisiana, the second and third largest petroleum refining States, respectively, jointly account for another 27 percent of crude distillation capacity.

The U.S. petroleum refining industry has suffered from an operating cost disadvantage when compared to foreign oil companies. U.S. oil companies face higher taxes and labor costs than their foreign counterparts. This partially explains why the United States imports a significant share of its oil requirements in the form of refined products (as opposed to crude). Consequently, the United States accounts for less than one percent of the world refinery capacity additions.

Iron and Steel Manufacturing Industry: The iron and steel industry (SIC 3312) consists of integrated establishments that produce basic steel shapes in the form of semi-finished products such as ingots, billets, blooms, and slabs or finished products such as steel strips, bars, shapes, heavy structurals, and rails. Establishements primarily engaged in producing finished products form purchased iron and steel (e.g., non-integrated) are considered separate industries and are classified under SIC codes 3315, 3316, and 3317.

Typically, operations at integrated steel works involve manufacturing iron from raw materials, refining the iron into steel, casting and milling the steel into semi-finished shapes, and either selling the shapes to non-integrated finishing facilities or hot rolling into finished products at the works. Integrated steel works range in size from large plants using several steel-making processes and finishing mills to small plants using a single process and selling a semi-finished product.

Over the last decade, the steel industry has suffered from recessionary trends rooted in the 1950's. Spiraling costs and restrained prices have reduced industry profits to low levels, leaving major steel producers with little capital for maintenance or expansion. As a result, domestic steel producers have been postponing large capital commitments, closing or selling unprofitable operations, reducing production levels, and merging with other companies.

Most of the capital investments made in recent years have been piece-meal expansions and replacements rather than large-scale capacity additions or new plants. Projects have attempted to cut costs by improving productivity, or boosting yields through modernization. It is likely that future investments will follow the same route of piece-meal expansions and replacements unless present market conditions improve.

Liquor Distilling Industry: The liquor distilling industry (SIC 2085) is made up of those establishments that manufacture liquor by distillation or rectification. They produce cordial and alcoholic cocktails by blending processes or by mixing liquors and other ingredients. All liquors except brandy are included in this category.

The liquor distilling industry is comprised of approximtely 50 firms that operate 100 distilleries. The greatest concentrations of distilling plants is located in the east south central States (Federal Region 4.) While distilleries are located in 25 States, Kentucky has 27 percent of the total number of domestic plants. California follows second with 11 percent of the total.

The number of plants that these firms operate has decreased in the past decade. In 1972, 121 distilleries were operating; by 1977, this sum had fallen to 104, a loss of 17 distilleries in five years. Apparently, no new facilities have been constructed in recent years. Several factors may explain the decreasing number of operating distilleries: some plants are old, inefficient, and not equipped for the major production modifications often necessary to satisfy the demands of a changing market; furthermore, large firms often find operating fewer plants more efficient.

The major inter-industry competition to the distilled spirits industry arises from the beer and wine industries. Beer and wine consumption has grown at the expense, to some degree, of "hard" liquors. Intensive advertising campaigns and brand proliferation has helped beer consumption grow. Wine, especially white wine, once just a dinner beverage, has become a cocktail beverage as well.

4.3 ECONOMIC IMPACT ANALYSIS

This section presents the analysis of economic impacts of an SO_2 alternative control level VI on industrial users of steam. The economic impact analysis is designed to determine if alternative SO_2 emission regulations for new industrial boilers will severely affect either major steam users or selected industries.

4.3.1 Major Steam Users Impacts

The economic analysis of the major steam users focuses on cost-related impacts. Capital availability considerations are best examined on a firm level and, therefore, are covered only in the analysis of the six selected industries.

The analysis of major steam users consists of four steps:

- Step One -- Evaluate price impacts of alternative regulatory options on a general industry level assuming the costs of the regulatory option are passed completely to the consumer (i.e., full cost pass-through).

- Step Two -- If price impacts are significant, evaluate the ability of the industry to pass through the entire costs.

- Step Three -- If industry is able to pass through costs, assess the macroeconomic impacts of the price increase. If industry is unable to pass on the additional costs, assess the ability of the industry to absorb the additional costs.

- Step Four -- If cost impacts are significant and the industry is unable to absorb the costs, further analysis is warranted for the impact on both the other industries (non-major steam users) and two-digit SIC industries.

The first step of the analysis evaluates the price impacts of alternative regulatory options on major steam users. When price impacts are determined to be significant, they are evaluated in terms of the conditions contained in Steps Two through Four.

The effect of a regulatory option on product price is calculated by finding the product of the change in the cost of new steam, the share of steam affected by the regulatory option, and the amount of steam consumed per dollar of output, as illustrated in Figure 2. The cost impacts are stated in real terms. The only real cost increase is assumed to be due to new boiler, pollution control, and fuel costs. All other production costs are held constant in real terms.

A summary of the product price impact for SO_2 alternative control level VI is found in Table 4-2. For each of the major steam users, the table shows:

- The industry's ratio of steam consumption to dollar of product shipments (in MMBtu/$ of shipment)
- Amount of total steam affected by the alternative SO_2 emission standard
- The change in the cost of steam for the reference fuel price scenario and higher oil and gas prices scenario
- The estimated change in the product price under each fuel price scenario.

The ratio of annual steam consumed (per unit output) to annual dollar value of shipment (per unit output) is computed by finding the quotient of annual steam consumption and the value of shipments. The ratio of annual steam consumed to annual dollar value of shipment by industry is assumed to remain constant over time. The estimated percent of steam affected by the alternative SO_2 standard is based on the amount of new steam demand projected for the 1986-1990 period as a fraction of total steam demand for each industry group. This percentage gradually increases over time as more new boilers become operational.

The alternative SO_2 standard examined does not affect product price significantly. As Table 4-2 shows, the product price increase is less than 0.1 percent for all industries. This result is due primarily to the relatively small fraction of total product value accounted for by new steam.

FIGURE 2. CHANGE IN PRODUCT PRICE DUE TO REGULATORY OPTION

$$\blacktriangle\begin{matrix}\text{Product}\\ \text{Price}\end{matrix} = \left\{\left(\begin{matrix}\text{GJ (MMBtu) Steam/}\\ \text{Product Price}\end{matrix}\right)\bullet\left(\begin{matrix}\text{Steam}\\ \text{Affected By}\\ \text{Regulatory}\\ \text{Option}\end{matrix}\right)\right\}\bullet\left\{\left(\begin{matrix}\text{Cost of}\\ \text{New Steam}\end{matrix}\right)_{\begin{matrix}\text{Regulatory}\\ \text{Option}\end{matrix}} - \left(\begin{matrix}\text{Cost of}\\ \text{New Steam}\end{matrix}\right)_{\begin{matrix}\text{Current}\\ \text{Regulation}\end{matrix}}\right\}$$

- GJ (MMBtu)/Steam Product Price

$$\frac{\text{Annual GJ (MMBtu) Steam/Annual Output (Total Number of Units)}}{\text{Annual \$ Value of Shipments/Annual Output (Total Number of Units)}}$$

- Steam Affected by Regulatory Option

$$\frac{\text{Steam Consumption Affected by Regulatory Option}}{\text{Total Steam Consumption}}$$

- Cost of New Steam

$$\frac{\text{Total Annualized Cost of Steam}}{\text{GJ (MMBtu)}}$$

TABLE 4-2. MAJOR STEAM USERS ECONOMIC IMPACTS[1/]

Industry	Steam/Product Price (MMBtu/$ of Shipments)	% Steam Affected	New Steam Cost Impact (Alternative SO_2 NSPS-Base Case) (1982 $/MMBtu)		Change in Product Price (Percent)	
			Reference fuel price scenario	Higher oil and gas prices scenario	Reference fuel price scenario	Higher oil and gas prices scenario
Food	.0035	9	0.32	0.10	0.01	0.01
Textiles	.0047	3	0.58	0.29	0.01	0.01
Paper	.0204	5	0.30	0.07	0.03	0.01
Chemicals	.0152	1	0.25	0.06	0.01	0.01
Petroleum Refining	.0042	0	-	-	-	-
Stone, Clay & Glass	.0014	0	-	-	-	-
Steel	.0060	1	0.56	0	0.01	0
Aluminum	.0147	1	0.17	0	0.01	0
Other	.0008	6	0.25	.06	0.01	0.01
Total	.0033	8	0.27	.06	0.01	0.01

[1/] The base case assumes the proposed PM and NO_x NSPS is in force. The alternative SO_2 standard is alternative control level VI (shown in Table 3-2).

The major steam users in aggregate will not experience a significant impact. This does not mean, however, that a component of the major steam user industry group will not be affected adversely. The selected industries study focuses both on industries from within the major steam users and from other manufacturing groups to assess whether smaller industry groups may be affected.

4.3.2 Selected Industries Impacts

The analysis of selected four-digit SIC industries forms the second part of the economic impact analysis. The major focus is the effect of the alternative NSPS on product cost, profitability, and capital availability for the firm. A small business analysis is also presented to evaluate the need for further review of the impacts under the Regulatory Flexibility Act.

4.3.2.1 Cost and Profitability Impacts Methodology

The following three steps are used to estimate the cost impact of regulatory options on a selected industry:

- Step One -- Define a model plant for the selected industry
- Step Two -- Evaluate the cost impacts for the model plant, assuming full cost absorption
- Step Three -- Evaluate the impacts on the profitability of the model plant

Each step is described below.

Model plant. The selected industries analysis focuses on model plants to measure the economic impact of SO_2 alternative control level VI on each industry. The model plant represents a typical plant for the segment of each industry that might be considering a boiler investment either as boiler expansion or replacement. A model plant is used since it is difficult to obtain precise details about the expansion and replacement plans of actual firms.

This analysis presents economic impacts for the model plant assuming the decision has already been made in the base case to expand or to replace its existing boilers. However, decisions regarding plant investments, including new steam generating capacity, ultimately depend on the market conditions faced by each firm. If it appears that it would be too costly for a firm with declining sales or a low profit margin to invest in a new boiler(s) and the necessary pollution control equipment, the firm could elect to defer the investment. A decision to defer the new boiler investment may be more attractive to the firm until the point at which it becomes too expensive to maintain the plant's existing boilers compared to replacing them with new units. The cost of installing and operating additional pollution control equipment to comply with the SO_2 alternative control level might also contribute to the possibility that the firm would defer the new boiler investment. However, the decision concerning new steam generating units is expected to depend more on the investment in new boiler equipment than the pollution control equipment due to the relative magnitude of their respective costs.

The fuel type burned in the existing boiler(s) of the model plant is determined by industry sources. The fuel type of the replacement or expansion boilers is based on industry trends and projections from IFCAM based on the combustor's size, location, and applicable energy and environmental regulations.

The following production characteristics for the model plant are supplied:

- Plant Output/Year -- average product output per year in those plants more likely to invest in new boilers.
- Price (Cost)/Unit of Output -- the historic, average selling price per unit, in real 1982 dollars.
- Plant Sales/Year -- plant output per year multiplied by price per unit of output.
- Plant Earnings/Year -- plant sales per year multiplied by a derived profit margin (percent return on sales). This figure estimates the profitability of the model plant.

Product Cost Impacts: The effect of regulatory options on product cost is calculated by finding the product of the change in the cost of new steam, the share of steam affected by the new regulation, and the amount of steam consumed per dollar of output. The cost impacts are stated in real terms. The only real cost increase is due to new boiler and fuel costs; all other real production costs are held constant.

It should be noted that the effect of the cost impact on product price is related to the market conditions for each firm and to what degree the firm behaves as a price-taker vs. a price-setter. The price impact is thus dependent on the extent that the firm is able to pass on the increased cost through increases in the price of its product(s).

The impact on a plant's value added is also determined. Value added represents the portion of the total product value that can be attributed to the plant's non-raw material costs of manufacturing the product. It covers the remaining product value after the cost of all material inputs have been deducted. The value added per dollar of product for each selected industry has been calculated nationally using U.S. Census of Manufacture's data on a four-digit SIC basis.

Profitability Impacts. The additional costs due to a regulatory option will affect the profitability of an industry. This impact will be assessed by examining the following two financial indicators for the model plant:

- Net Profit After Taxes (Net Income). Profit after all costs and taxes have been deducted.
- Return on Assets. Net income divided by total assets, converted to a percent form.

The change in these indicators due to regulatory options is a measure of the ability of the model plant to absorb the additional costs of a regulatory option.

4.3.2.2 Capital Availability

Capital availability constraints may result if a regulatory option creates a need for financing additional pollution control investments. The firm is the focus of the capital availability analysis because decisions involving large capital expenditures are made at the corporate level. Depending upon the state of corporate cash reserves and the relative costs of various financing tools, a firm will choose a combination of internal and external financing instruments to meet the additional investments required to comply with regulatory option.

The capital availability analysis focuses on the following two financial indicators, which ensure each industry's financing ability:

- Coverage Ratio -- the number of times operating income (earnings before taxes and interest expenses) covers fixed obligations (annual interest on debt instruments and long-term leases)
- Debt/Equity Ratio -- a measure of the relative proportions of two types of external financing.

These two indicators are analyzed for both the base case and the regulatory options. The change in indicators due to the regulatory option is analyzed to determine how difficult it will be for the firm to meet financial requirements for the pollution control equipment investment.

The cash flow coverage ratio is calculated by dividing operating income by fixed obligations, both of which could change as a result of alternative regulatory options. If the coverage ratio remains above the 3.0 standard benchmark, the cost of capital can be assumed to be above "acceptable" levels. However, as the coverage ratio falls, the cost of obtaining capital will rise.

The debt/equity ratio is calculated by dividing total debt by total equity of the firm (book values). The incremental debt incurred from financing the pollution control required by the regulatory option is added to the base case debt. A new debt/equity ratio then is calculated and the change is analyzed to assess the effect of the regulatory option on the firm's capital structure.

4.3.2.3 Summary of Selected Industry Economic Impacts

A summary of the key economic impacts results for selected industries is shown in Table 4-3. The impact on product cost and value added is less than 1.0 percent for all industries, except for beet sugar refining. The larger impact on the beet sugar refining model plant reflects the relatively large portion of product costs attributable to generating steam for the refining process. However, as discussed further below, this impact is not expected to have a significant effect on the beet sugar refining industry. The impact on the model firms return-on-assets for the selected industries is a decrease of 0.1 to 2.8 percentage points. The largest impact on return-on-asset occurs for the model firm in the rubber reclaiming industry.

A summary discussion of the impacts for each selected industry is presented below.

4.3.2.4 Beet Sugar Refining Industry

Model firm and plant description. The major characteristics of the model plant and firm for the beet sugar refining industry are listed in Table 4-4. The model firm is made up of four plants, which are located in the north central United States (Federal Region 8). Each plant is identical in its steam use and product output.

TABLE 4-3. SUMMARY OF KEY ECONOMIC IMPACTS OF SO_2 ALTERNATIVE CONTROL LEVEL VI ON SELECTED INDUSTRIES

Selected Industry	Increase in the model plant's: Product cost (percent)	Increase in the model plant's: Value added cost (percent)	Decrease in the model Firm's return on assets (percentage points)
Beet Sugar Refining	1.5	5.0	0.8
Rubber Reclaiming	0.5	0.9	2.8
Auto Manufacturing	0.004	0.12	0.1
Petroleum Refining	0.02	0.14	0.1
Iron and Steel Mfg.	0.10	0.25	0.1
Liquor Distilling	0.12	0.24	0.3

TABLE 4-4. MODEL FIRM AND PLANT CONFIGURATION: BEET SUGAR INDUSTRY

Model firm

Financial data[a]

Average bond rating: Baa
Coverage ratio: 12.3
Debt/equity ratio: 0.25

Model plant

Production data[a]

Plant output/year: 74,000 megagrams (81,000 tons)[b]
Price/unit output: $68.60/hundred kilogram wt.[c] ($31.20/hundred pound wt.)
Plant sales/year: $50.5 million [c]
Plant earnings/year: 2.22 million[c,d]

Boiler configuration

Total firing rate: 114 MW (390 MMBtu/hr)
No. of boilers: 3
Federal region: 8

Characteristics of individual boilers

	Boiler		
	1	2	3
Capacity, MW (MMBtu/hr)	51 (175)	51 (175)	12 (40)
Fuel type	coal	coal	residual fuel oil
Annual capacity utilization, percent	45	45	25
Replacement, expansion or existing	replacement		existing

---

[a] Based upon 1981 values.

[b] Based upon the average production of the portion of the industry most likely to invest in a new boiler.

[c] Expressed in 1982 dollars.

[d] Based upon the 1981 average return on sales ratio of 4.4 percent.

Total annual firm production is 294,000 megagrams (324,000 tons) of sugar, with annual sugar sales at $207 million, assuming that beet sugar sells for $68.60 per hundred kilograms ($31.20 per hundred pounds) and that none of this sugar is added to existing inventories. Annual profits are 4.4 percent of total sales or about $2.2 million.

The model plant boiler house consists of three fossil fuel-fired boilers with a total heat input capacity of 114 MW (390 MMBtu/hr). Table 4-4 describes the individual boilers. The two boilers being replaced have a heat input capacity of 51 MW (175 MMBtu/hr) and an annual capacity utilization of 45 percent. Approximately 90 percent of total steam generated for the plant is from these new boilers. The two new boilers are primarily used for process heat and electricity generation.

Regulatory Impacts. In the base case, all the plant's boiler replacements are subject to an SO_2 SIP emission regulation and the proposed PM/NO_x NSPS for industrial boilers. Industry representatives expect that any new boilers of this size will fire coal. IFCAM projects that coal is the least-cost fuel type and that a low sulfur western coal is the least-cost coal type. A fabric filter will be installed to ensure that particulate emissions do not exceed the proposed PM standard in the base case.

The projected economic impacts for the beet sugar model plant and firm are shown on Table 4-5. As a result of installing FGD equipment to comply with the alternative SO_2 standard, beet sugar production costs for the model plant are estimated to increase 1.5 percent. The impact on the plant's value added portion of total production costs is 5.0 percent (using a value added-to-value of shipments ratio of 0.3). Based on a threshold standard of 5.0 percent for measuring the cost impact of a regulatory option, the impact on total plant production costs is within the range where adverse impacts are not expected to become significant. Since the product cost and value added impacts occur at only one of the firm's four plants, these costs could actually be factored into the firm's total beet sugar production and actually result in a lower overall price impact.

The impact on the firm's net income, as shown in Table 4-5, reduces its annual income from $1.1 million to $0.7 million, This decrease in net revenues is estimated to lower the model firm's return-on-assets

TABLE 4-5. ECONOMIC IMPACTS OF SO_2 ALTERNATIVE CONTROL LEVEL VI FOR BEET SUGAR REFINING

Percent increase in plant's product cost:	1.5
Percent increase in value added cost:	5.0
Model firm:	
Net income after taxes (10^6 1982 $)	
Base Case:	1.1
Alternative control level VI:	0.7
Return on assets for firm (percent):	
Base Case:	2.3
Alternative control level VI:	1.5

Capital availability impacts:

	Percent financed by debt	
	0%	100%
Coverage ratio:		
Base Case:	12.33	9.07
Alternative control level VI	12.33	8.95
Debt/equity ratio:		
Base Case	0.217	0.361
Alternative control level VI	0.217	0.366

from 2.3 percent to 1.5 percent. Many beet sugar plants have been able historically to operate with low profit margins, since beet sugar growers in many cases cooperatively own the plant and maintain its operation to process their sugar beets. Beet sugar firms have been increasing their use of coal in their plants to help reduce energy costs and help maintain their profit margins. Even with the FGD requirement to meet the alternative SO_2 standard, it is expected that the cost of using oil and gas over the long-run will be higher than installing coal-fired boilers and the necessary pollution control equipment. Thus the lower rate of profits due to the alternative SO_2 standard is expected to be less severe than if the plant continues to use its existing oil- or gas-fired boilers.

The effect of the alternative SO_2 standard on the model firms coverage ratio and debt/equity ratio are also presented in Table 4-5. There is a small decrease in the coverage ratio from 9.07 to 8.95 when 100 percent debt financing is assumed. The ratios are well above the 3.0 acceptable benchmark. The debt/equity ratio increases in the base case from 0.217 to 0.361 when comparing zero percent to 100 percent debt financing. However, the impact of increased debt financing due to the SO_2 alternative standard has minimal effect on the debt/equity ratio and will not change this firm's ability to secure financing for the additional capital investment for SO_2 pollution control equipment.

It should be noted that the proposed standard is not expected to be the primary criterion in the decision to install a new steam plant. The firm will need to evaluate the investment as being cost-effective with or without more stringent emission regulations. Given the low rate of return in these firms, the major issue is whether any capital investment is justified, even with the intent of reducing energy costs by installing a coal-fired boiler. Under the alternative SO_2 standard, the firm still would save energy costs in the long-term by installing the coal-fired boiler, although savings would be less than in the base case.

4.3.2.5 Rubber Reclaiming Industry

Model firm and plant description. Table 4-6 presents the model plant and firm for the rubber reclaiming industry. Each plant within the industry is assumed to be identical in its production process; each produces the same amount of output with equal amounts of steam. The

TABLE 4-6. MODEL FIRM AND PLANT CONFIGURATION: RUBBER RECLAIMING INDUSTRY

Model firm

Financial data[a]

Average bond rating: N.A.[b]
Coverage ratio: 9.9
Debt/equity ratio: 0.24

Model plant

Production data[a]

Plant output/year: 18,100 megagrams (20,000 tons)[c]
Price/unit output: $0.53/kilogram ($0.24/pound)[d]
Plant sales/year: $9.3 million [d]
Plant earnings/year: $0.49 million[d,e]

Boiler configuration

Total firing rate: 66.8MW (224 MMBtu/hr)
No. of boilers: 3
Federal region: 8

Characteristics of individual boilers

	Boiler		
	1	2	3
Capacity, MW (MMBtu/hr)	29 (100)	18.2 (62)	18.2 (62)
Fuel type	coal	oil/gas	oil/gas
Annual capacity utilization, percent	45	45	45
Replacement, expansion or existing	replacement	existing	

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[a] 1978 values.

[b] N.A. = Not available.

[c] Average of plant output/year for 1974 - 1978.

[d] Expressed in 1982 dollars.

[e] Based upon the 1978 return on sales ratio of 5.2 percent.

typical plant operates in the midwestern United States and has a yearly output of 18,100 megagrams (20,000 tons). The typical producer selling price is $0.53 per kilogram ($0.24 per pound), yielding sales of $9.3 million. Applying an industry-wide profit margin of 5.2 percent of sales, the model plant earns $480,000 in profit.

The typical plant's boiler house contains three boilers that have a combined firing capacity of 66 MW (224 MMBtu/hr). All boilers are assumed to operate at 45 percent of annual rated capacity.

Regulatory Impacts. The replacement boilers under both the base case and the SO_2 alternative standard is assumed to burn coal. In the base case, in order to meet the proposed PM/NO_x emission regulation, the plant will install a fabric filter on the boiler.

A summary of the economic impacts is presented in Table 4-7 for the rubber reclaiming industry model firm. The increase in the model plant's product costs and value added costs due to the SO_2 control on the 100 MMBtu/hr boiler are both less than 1.0 percent.

Table 4-7 includes the change in net income due to the alternative SO_2 standard. The impact on profits assumes that sales are constant in real terms and that expenses rise only due to the new boiler investment for the 100 MMBtu/hr unit. Assuming a 50 percent corporate income tax, net income decreases from $210,000 in the base case to $60,000. Return on assets for the model plant decreases from 3.8 percent for the base case to 1.0 percent under the alternative SO_2 standard.

Table 4-7 also lists the rubber reclaiming industry's coverage ratio and debt/equity ratio for two financing options for the additional capital investment. The coverage and debt/equity ratios do not change significantly between the base case and the SO_2 alternative standard case. These ratios do vary, however, depending on the financing strategy. For example, the coverage ratio decreases from 9.9 to 6.7 in the base case. While this represents a 32 percent decrease, the average ratio is still above the 3.0 standard benchmark. The debt/equity ratio for the alternative SO_2 standard varies from 0.24 to 0.32 which is well below the 1.0 threshold level. The low long-term debt proportion suggests that the industry may have unused debt capacity. Assuming that the firm will finance externally, the majority of the external funds may come from debt instruments.

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TABLE 4-7. ECONOMIC IMPACTS OF SO_2 ALTERNATIVE CONTROL LEVEL VI FOR RUBBER RECLAIMING

Percent increase in plant's product cost:	0.5	
Percent increase in value added cost:	0.9	
Model firm:		
Net income after taxes (10^6 1982 $)		
Base Case:	0.21	
Alternative control level VI:	0.06	
Return on assets for firm (percent):		
Base Case:	3.8	
Alternative control level VI:	1.0	
Capital availability impacts:		
	Percent financed by debt	
	0%	100%
Coverage ratio:		
Base Case:	9.9	6.7
Alternative control level VI	9.9	6.6
Debt/equity ratio:		
Base Case	.24	.31
Alternative control level VI	.24	.32

The results of the analysis indicate that the regulatory option cause percentage increases in product cost of one percent or less. Profits remain positive, although relatively low, under the alternative SO_2 standard. Data on capital availability suggest that the firm will be able to finance the new boiler and control equipment investment under the alternative SO_2 standard.

The firm may elect to defer its investment in new boiler and pollution control equipment until its profit margin improves. But, as noted earlier, the installation of a new coal-fired boiler should reduce energy costs in the long-term, even though those savings would be reduced by the added cost of complying with the alternative SO_2 standard.

4.3.2.6 Automobile Manufacturing Industry

Model firm and plant description. The model firm and plant configuration for the automobile manufacturing industry is presented in Table 4-8. The plant that operates in Federal Region 5 is assumed to be part of a 26-plant firm. Total firm production is 2,340,000 vehicles, with annual car and light truck sales of $20.4 billion, assuming an average price (1982 dollars) of $8,670 per vehicle. These production statistics do not include foreign-made cars (such as the Dodge colt or the Chevrolet Sprint) normally part of the United States automobile companies' fleets. Because these cars are not produced in this country, their production costs would not be affected by alternative regulatory options. Net profit for the model firm is assumed to be 4.28 percent of total sales, or $873 million.

The model plant boiler house consists of four coal-fired boilers with a total heat input capacity of 106 MW (361 MMBtu/hr). The boiler investment decision is to replace one of these units with a similarly sized new coal-fired boiler.

Regulatory Impacts. In the base case, the plant's boiler replacement must comply with SO_2 SIP air emission limits and the proposed PM/NO_x NSPS. Based on historical industry trends, the fuel for the new boiler is projected to be coal. In the base case, the plant will install a fabric filter for PM control. A once-through sodium FGD will be installed to comply with the alternative SO_2 standard.

TABLE 4-8. MODEL FIRM AND PLANT CONFIGURATION: AUTOMOBILE MANUFACTURING INDUSTRY

Model firm

Financial data[a]

Average bond rating: Aaa/B
Coverage ratio: 20.17
Debt/equity ratio: 0.11

Model plant

Production data[a]

Plant output/year: 90,130 automobiles[b]
Price/unit output: $8,686 automobile[c]
Assembly plant sales/yr: $782.9 million[c]
Assembly plant earnings/year: $33.5 million[c,d]

Boiler configuration

Total firing rate: 106 MW (361 MMBtu/hr)
No. of boilers: 4
Federal region: 5

Characteristics of individual boilers

	Boiler			
	1	2	3	4
Capacity, MW (MMBtu/hr)	25.5 (87)	25.5 (87)	25.5 (87)	29 (100)
Fuel type	coal	coal	coal	coal
Annual capacity utilization, percent	0[e]	25	25	25
Replacement, expansion or existing	existing			replacement

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[a] 1978 values.

[b] Based upon average industry estimates.

[c] Expressed in 1982 dollars.

[d] Based upon the 1978 return on sales ratio of 4.28 percent.

[e] Boiler number one is used as a standby boiler.

The estimated economic impacts for the auto industry model firm are summarized in Table 4-9. Production cost and value added impacts are negligible (i.e., less than 0.1 percent).

Table 4-9 shows the change in profit margin for the automotive industry. Because the boiler investment is such a small fraction of total expenses, the net income changes due to a regulatory option are small compared to the base case. The alternative SO_2 standard results in a less than one percent decline in net income compared to the base case. Return on assets remains constant at 9.17.

The coverage and debt/equity ratios for the automobile manufacturing industry are also shown in Table 4-9. The coverage ratio declines slightly from 20.17 to 20.10. The debt/equity ratio remains at 0.11. Neither of these ratios suggests problems in obtaining capital in either of the regulatory options. Since these rates show a low percentage of debt, future investments could be funded largely from debt, depending upon the interest rate and the industry's inclination toward debt financing.

The results of the analysis indicate that the alternative SO_2 standard does not significantly affect any of the above financial parameters. The impact on product cost is negligible due to the low ratio of new steam cost to total dollar output. Capital availability is not constrained by any of these cases, suggesting that the firm will be able to finance a new boiler replacement.

4.3.2.7 Petroleum Refining Industry

Model firm and plant description. Table 4-10 presents the model firm and plant for the petroleum refining industry. This plant, operating in the Southwest (Federal Region 6), is assumed to be part of a seven-plant firm. Total production for the model firm is 112.93 million barrels of refined product per year. Assuming a price of \$33.65 per barrel and an annual net profit margin of 4.51 percent, the firm realizes annual sales of \$3.8 billion and annual profits of \$171.4 million. Comparing these figures to 1978 U.S. refined product consumption, this firm satisfies approximately two percent of total demand and accounts for about four percent of the domestically refined petroleum products market.

TABLE 4-9. ECONOMIC IMPACTS OF SO_2 ALTERNATIVE CONTROL LEVEL VI FOR AUTOMOBILE MANUFACTURING

Percent increase in plant's product cost:	.004
Percent increase in value added cost:	.012
Model firm:	
Net income after taxes (10^6 1982 $)	
Base Case:	37.8
Alternative control level VI:	37.6
Return on assets for firm (percent):	
Base Case:	9.17
Alternative control level VI:	9.14

Capital availability impacts:

	Percent financed by debt	
	0%	100%
Coverage ratio:		
Base Case:	20.17	20.10
Alternative control level VI	20.17	20.10
Debt/equity ratio:		
Base Case	.11	.11
Alternative control level VI	.11	.11

TABLE 4-10. MODEL FIRM AND PLANT CONFIGURATION: PETROLEUM REFINING INDUSTRY

Model firm

Financial data[a]

Average bond rating: Aaa/A
Coverage ratio: 14.12
Debt/equity ratio: 0.32

Model plant

Production data[a]

Plant output/year: 16,133 barrels
Price/unit output: $33.65 per barrel[b,c]
Plant sales/year: $543.9 million[c]
Plant earnings/year: $24.5 million[c,d]

Boiler configuration

Total firing rate: 381.0 MW (1300 MMBtu/hr)
No. of boilers: 4
Federal region: 6

Characteristics of individual boilers

	Boiler			
	1	2	3	4
Capacity, MW (MMBtu/hr)	95.2 (325)	95.2 (325)	95.2 (325)	95.2 (325)
Fuel type	refinery gas	refinery gas	natural gas	coal
Annual capacity utilization, percent	75	75	75	75
Replacement, expansion or existing	existing			replacement

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[a] 1978 values.

[b] The price per unit output is based upon the average price for all refined products.

[c] Expressed in 1978 dollars.

[d] Based upon the 1978 return on sales ratio of 4.51 percent.

The model plant boiler house consists of four boilers, with a total heat input capacity of 381 MW (1,300 MMBtu/hr). Each boiler has a firing capacity of 95 MW (325 MMBtu/hr) and is used at 75 percent of heat input capacity. Three of the boilers are existing units, firing refinery and natural gas. The fourth unit, firing a mixture of petroleum coke and residual oil, will be replaced by a new coal-firing boiler in 1990. Approximately 25 percent of boiler steam generation for this plant will be provided by the new coal-firing boiler.

Regulatory Impacts. Historically, a significant share of the boiler fossil fuel demand in the petroleum refining industry has been met with the use of liquid, solid, and gaseous waste by-products of refinery operations. Because the focus of this analysis is on the choice between coal, oil, and gas, the fuel type for the new boiler is limited to these fuels. The new boiler under both the base case and the alternative SO_2 standard is assumed to burn coal.

Table 4-11 presents the change in product cost and value added for the refining plant due to the alternative SO_2 standard. Assuming 100 percent cost pass-through, the price impact is less than 0.1 percent. This small percentage is due primarily to the small fraction that new steam costs comprises of total product cost. Table 4-11 also shows that net income for the refinery company decreases about one percent to $33.3 million.

The coverage and debt/equity ratios for the model petroleum refinery indicate that neither the regulatory option nor the financing strategy affect these ratios significantly. The coverage ratio decreases from 14.12 to 14.08, or less than 0.3 percent. The debt/equity ratio remains at 0.32 under all financing options.

The results of the analysis indicate that the alternative SO_2 standard does not result in significant cost impacts on the petroleum refining industry. Profitability is affected only slightly by the incremental expenses due to new boiler investment. Return on assets, however, remains at 5.9 percent under the base case and alternative SO_2 standard.

Capital availability appears to be stable for the petroleum refining industry. The coverage ratio is sufficiently high to assume

TABLE 4-11. ECONOMIC IMPACTS OF SO_2 ALTERNATIVE CONTROL LEVEL VI FOR PETROLEUM REFINING

Percent increase in plant's product cost:	.02	
Percent increase in value added cost:	.14	
Model firm:		
Net income after taxes (10^6 1982 $)		
Base Case:	33.6	
Alternative control level VI:	33.3	
Return on assets for firm (percent):		
Base Case:	5.98	
Alternative control level VI:	5.93	
Capital availability impacts:		
	Percent financed by debt	
	0%	100%
Coverage ratio:		
Base Case:	14.12	14.08
Alternative control level VI	14.12	14.08
Debt/equity ratio:		
Base Case	.32	.32
Alternative control level VI	.32	.32

that the refinery will not have problems obtaining external funds for the boiler investment.

4.3.2.8 Iron and Steel Manufacturing Industry

Model firm and plant description. Table 4-12 depicts the model firm and plant for the integrated iron and steel industry. This plant is assumed to be part of a five-plant firm, located in the midwestern States. Total production for the model firm is 8.2 million megagrams (9.0 million tons) of raw steel per year. Assuming a real price of $534 per megagram ($480 per ton) and an annual net profit margin of 2.9 percent, the firm realizes annual sales of $4.3 billion and annual profits of $126.4 million.

The model plant boiler house consists of four boilers with a total heat input capacity of 216 MW (736 MMBtu/hr). Three of the boilers have a capacity of 40 MW (137 MMBtu/hr) and the fourth has a capacity of 95 MW (325 MMBtu/hr). All the boilers currently fire blast furnace gas and have an annual capacity utilization of 55 percent. The three 40 MW boilers are retired and assumed to be replaced by three similarly sized coal-fired boilers. Approximately 55 percent of boiler steam generation for this plant will be provided by the new coal-fired boilers. To comply with the alternative SO_2 standard, a once-through sodium FGD system is installed.

Regulatory Impacts. Table 4-13 indicates that there is no significant change in product cost, value added, or profitability for the industry as a result of the changes in cost of new steam. The profitability analysis for the base case and alternative SO_2 standard assumes that sales are held constant in real terms and that expenses increase only as a result of new boiler investment. This incremental expense is assumed to be absorbed by the firm and is not passed on to the consumer. Given this assumption, net income is $24.0 million in the base case and $23.4 million in the alternative SO_2 standard case. Return on assets decreases from 3.36 percent to 3.28 percent. Because of the relatively large sales and expense base for the industry, the incremental expense brought about by the increase in new steam cost of the alternative SO_2 standard does not significantly affect the firm's profitability.

TABLE 4-12. MODEL FIRM AND PLANT CONFIGURATION: IRON AND STEEL MANUFACTURING INDUSTRY

Model firm

Financial data[a]

Average bond rating:	N.A.[b]
Coverage ratio:	6.09
Debt/equity ratio:	0.52

Model plant

Production data[a]

Plant output/year:	1,632,600 megagrams 1,800,000 tons)
Price/unit output:	$534 megagram (484 per ton)[c]
Plant sales/year:	$870.7 million [c]
Plant earnings/year:	$25.3 million[c,d]

Boiler configuration

Total firing rate:	215 MW (736 MMBtu/hr)
No. of boilers:	4
Federal region:	5

Characteristics of individual boilers

	Boiler 1	Boiler 2	Boiler 3	Boiler 4
Capacity, MW (MMBtu/hr)	40.1 (137)	40.1 (137)	40.1 (137)	95.2 (325)
Fuel type	coal	coal	coal	blast furnace gas
Annual capacity utilization, percent	55	55	55	55
Replacement, expansion or existing	replacement			existing

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[a] 1978 values.

[b] N.A. = Not available.

[c] Expressed in 1982 dollars.

[d] Based upon the 1978 return on sales ratio of 2.9 percent.

TABLE 4-13. ECONOMIC IMPACTS OF SO_2 ALTERNATIVE CONTROL LEVEL VI FOR IRON AND STEEL

Percent increase in plant's product cost:	0.1
Percent increase in value added cost:	0.25
Model firm:	
Net income after taxes (10^6 1982 $)	
Base Case:	24.0
Alternative control level VI:	23.4
Return on assets for firm (percent):	
Base Case:	3.36
Alternative control level VI:	3.28

Capital availability impacts:

	Percent financed by debt	
	0%	100%
Coverage ratio:		
Base Case:	6.09	5.82
Alternative control level VI	6.09	5.80
Debt/equity ratio:		
Base Case	.52	.52
Alternative control level VI	.54	.54

Table 4-13 also shows that coverage and debt/equity ratios do not vary significantly as a function of the regulatory option. The coverage ratio decreases from approximately 6.09 with zero percent debt financing to approximately 5.82 with 100 percent debt in the base case. The alternative SO_2 standard will reduce the coverage ratio to 5.82 under the 100 percent debt financing case. The debt/equity ratios vary from 0.52 to 0.54 for the various financing strategies.

The results of the analysis indicate that the regulatory options cause low percentage increases in product cost. New steam costs for the regulatory options comprise a relatively small portion of average product cost. Profitability likewise is affected slightly by the incremental expenses due to new boiler investment.

With regard to financing capability, the analysis of coverage ratios indicates that new boiler investment can be funded with up to 100 percent debt. The 3.0 coverage benchmark is always exceeded even when total debt financing is assumed. This firm's solvency position remains stable even when total debt financing is undertaken. Due to the industry's large equity base, the debt ratios do not exhibit wide variances as a result of the two financing options.

4.3.2.9 Liquor Distilling Industry

Model firm and plant description. The model plant and boiler configuration of the liquor distilling industry is shown in Table 4-14. It is assumed that the typical firm operates three plants. The model plant is located in a southeastern State and produces 17 million liters (4.5 million gallons) of distilled liquor annually.

The model plant operates two boilers, one rated at 29 MW (100 MMBtu/hr), the other at 18 MW (62 MMBtu/hr), with a total firing capacity of 47 MW (162 MMBtu/hr) and 45 percent capacity utilization. The model plant elects to replace the larger natural gas/oil-fired boiler with an identically configured coal-fired boiler.

Regulatory Impacts. The model plant replacement boilers for the liquor distilling industry are assumed to be coal-fired. To meet the proposed PM/NO_x NSPS in the base case, a fabric filter is installed for PM control.

Table 4-15 illustrates the changes in product cost, value added, and profitability due to the SO_2 alternative standard. Sales are

TABLE 4-14. MODEL FIRM AND PLANT CONFIGURATION: LIQUOR DISTILLING INDUSTRY

Model firm

Financial data[a]

Average bond rating:	N.A.[b]
Coverage ratio:	5.44
Debt/equity ratio:	0.292

Model plant

Production data[a]

Plant output/year:	[illegible].0 millio[illegible] (4.5 million gallons
Price/unit output:	$[illegible].31 liter [illegible] gallon)[c]
Plant sales/year:	$39.2 mill[illegible]
Plant earnings/year:	$1.68 milli[illegible]

Boiler configuration

Total firing rate:	47.3 MW (16[illegible] [illegible]/hr)
No. of boilers:	2
Federal region:	4

Characteristics of individual boilers

	Boil[illegible]	
	1	2
Capacity, MW (MMBtu/hr)	29 (100)	[illegible]8.2 (62)
Fuel type	coal	oil/gas
Annual capacity utilization, percent	45	4[illegible]
Replacement, expansion or existing	replacement	existing

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[a] [illegible]7[illegible] values.

[b] N.A. = Not available.

[c] Expressed in 198[illegible] dollars.

[d] Based upon the 1978 return on sales ratio of 2.9 percent.

TABLE 4-15. ECONOMIC IMPACTS OF SO_2 ALTERNATIVE CONTROL LEVEL VI FOR LIQUOR DISTILLING

Percent increase in plant's product cost:	0.12
Percent increase in value added cost:	0.24
Model firm:	
Net income after taxes (10^6 1982 $)	
Base Case:	0.29
Alternative control level VI:	0.17
Return on assets for firm (percent):	
Base Case:	.68
Alternative control level VI:	.37
Capital availability impacts:	

	Percent financed by debt	
	0%	100%
Coverage ratio:		
Base Case:	5.44	4.32
Alternative control level VI	5.44	4.26
Debt/equity ratio:		
Base Case	.29	.36
Alternative control level VI	.29	.37

assumed to be constant in both regulatory options, and expenses increase only as a result of the new boiler investment. Net income level decreases from $290,000 in the base case to $170,000 under the SO_2 alternative standard. Return on assets is 0.68 percent in the base case and 0.37 percent under the alternative SO_2 standard.

Table 4-15 also presents comparative coverage and debt/equity ratios for the alternative SO_2 standard. These results show the coverage ratio in the base case decreasing from 5.44 with zero percent new debt to 4.32 with 100 percent debt. The coverage ratio decreases from 5.44 to 4.26 for zero and 100 percent financing under the alternative SO_2 standard. However, both coverage ratios are still above the 3.0 coverage benchmark.

The results of the analysis indicate that product cost is expected to increase by slightly over one-half of a percent. New steam costs for the alternative SO_2 standard comprise a relatively small portion of average product cost. Profitability shows a decline as a result of the SO_2 regulatory option when compared to the base case. Return on assets decreases from 0.68 percent in the base case to 0.37 percent.

The firm may elect to defer its investment in new boiler and pollution control equipment until its profit margin improves. But, as noted earlier, the installation of a new coal-fired boiler should reduce energy costs in the long-term, even though those savings would be reduced by the added cost of complying with the alternative SO_2 standard.

With regard to financing capability, the analysis of coverage ratios indicates that new boiler investment can be funded totally by debt while still meeting the 3.0 coverage benchmark. The industry maintains a relatively stablized solvency position even when 100 percent debt financing is assumed.

4.3.3 Small Business Analysis

The effects of SO_2 standards on small businesses are considered in this section. For six of the seven industries, small plants are characterized in Table 4-16.

For beet sugar, iron and steel, distilled liquor, and petroleum refining, average-size small plants are examined. Using 1977 Census data on plant sales and the Small Business Administration's definition

TABLE 4-16. SMALL PLANTS
IN SELECTED INDUSTRIES

	Small plant characteristics		
SIC)	Max. employees[a]	Average sales[b] (10^6)	(MMBtu/hr)
Beet sugar (1063)	750	23.1	175
Iron and steel (3312)	1,000	14.2	125
Distilled liquor (2085)	750	22.7	125
Petroleum refining (2911)	1,500	224.1	100
Auto manufacturing (3711)	1,000	252.1[d]	100[d]
Reclaimed rubber (3031)	750	9.3[e]	224[e]
Fruit and vegetable canning (2033)	500	NA[f]	NA[f]

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[a] Small Business Size Standards, SBA Rules and Regulations. July 15, 1980 45FR47415. Schedule A. Definition of Small Business for the Purpose of Pollution Control Guarantee Assistance under PL94-305. Section 121.3-16.

[b] Except as noted, small plant sales represent the average sales of small plants in the 1977 Census of Manufacturers, converted to 1982 dollars using the GNP price deflator.

[c] Boiler sizes for small plants are estimated using the same heat intensities as at the large plants in each industry.

[d] The small plant shown is that which would need a 100 MMBtu/hr boiler.

[e] The average plant in this industry is a small plant.

[f] Not applicable. Plants are fired by natural gas and are consequently not likely to be affected by the SO_2 standards.

of small plants in each industry (a maximum of 750 to 1,500 employees), the average sales per plant was calculated among all plants classified as small in each industry. In turn, sales were converted to 1982 dollars using the GNP price deflator.

Corresponding boiler capacities were estimated for such small plants by using the boiler heat intensities per dollar of product described earlier for large plants in the same industries.

The same procedure was followed to estimate the size of a small automobile manufacturing plant; however, the average small plant would have only a three MMBtu/hr boiler. The small plant used instead in this analysis is scaled up to the size that uses a 100 MMBtu/hour boiler; this is still within SBA's definition of small for that industry.

In the case of reclaimed rubber, it was found that the average plant analyzed in Section 4.3.2.5 was already a small plant, and that further analysis of this industry is not needed in this section.

Fruit and vegetable canning plants also are not analyzed in this section, because they burn natural gas in their boilers and therefore would not be affected by standards for SO_2 emissions.

Potential impacts for small plants in the first five industries are summarized in Table 4-17. The results show how small plants would be affected and address EPA's four guideline criteria for determining whether a Regulatory Flexibility Analysis is needed:

- Annual compliance costs are compared to base case production costs (sales, less net income and taxes);
- Annual compliance costs as a percentage of sales are compared for small versus large plants (model plants from the BIDs);
- The debt-to-equity ratio with control equipment outlays financed entirely from debt is compared with the base case ratio to assess capital adequacy;
- Net income as a percent of sales is measured to determine plant profitability (or closure) with full absorption of the annualized compliance costs.

Results for small plants in each of the five industries showed that no industry would need a formal Regulatory Flexibility Analysis. Annualized compliance costs range from 0.1 to 2.9 percent of production

TABLE 4-17. INDUSTRIAL BOILERS NSPS
SMALL BUSINESS IMPACT ANALYSIS TO STUDY NEED FOR A REGULATORY FLEXIBILITY ANALYSIS

Selected industries	Product cost impact for average small plant[a] (percent)	Total annualized cost as percent of sales for small and large model plants: Small Plant	Large Plant[b]	Debt/equity ratios for small firm under base case and alternative standard: Base Case	Alternative Standards	Net income as percent of sales to gauge the Potential for plant closure[c]
Beet sugar, SIC 2063	1.7	1.7	1.5	0.22	0.48	0.5
Iron and steel, SIC 3312	2.9	2.8	0.1	0.52	0.69	1.2
Distilled liquor, SIC 2045	1.4	1.3	0.1	0.29	0.36	1.9
Petroleum refining, SIC 2911	0.1	0.1	0.0	0.32	0.33	4.4
Auto manufacturing, SIC 3711	0.1	0.1	0.0	0.11	0.12	4.2

[a] Product cost impact is calculated by dividing the increase in total annualized costs due to additional pollution control equipment by the annual production costs for the average small plant.

[b] Large plant data is based on Table 4-3.

[c] Assuming full cost absorption after controls.

costs at the five industries, below EPA's guideline threshold of five percent. Annualized compliance costs as a percentage of sales at small versus large plants similarly do not exceed EPA's guidelines. The differential for small plants ranges from 0.1 to 2.7 percentage points, below EPA's guideline level of 10 percentage points.

The debt-to-equity ratio remains below 1.0, the benchmark used in the BID. Assuming that capital investments for SO_2 emissions control are financed 100 percent by debt, the debt ratios of the controls range from 0.12 to 0.69. This shows residual capital availability for small plants even after compliance with the standards.

Finally, no small plants would likely close due to the recommended standards. Net income with full absorption of compliance costs would remain positive. New income as a percent of sales ranges from 0.5 to 4.4 percent of sales.

In sum, none of EPA's guidelines for a formal Regulatory Flexibility Act Analysis is triggered in the analysis of small plant impacts.

APPENDIX A
OVERVIEW OF IFCAM

A.1 PURPOSE

The Industrial Fuel Choice Analysis Model (IFCAM) is an energy demand model developed by Energy and Environmental Analysis, Inc. (EEA) to evaluate fuel choice decisions in the industrial sector over a five to 15-year forecasting horizon. IFCAM is a highly disaggregated process engineering model* designed to analyze factors affecting fuel choice decisions in industrial boiler energy applications.

IFCAM assesses the impacts of four sets of factors affecting industrial fuel choice: fuel prices, State and Federal energy and environmental policy proposals, the costs associated with firing alternate fuels, and other key model parameters such as the expected size distribution of new industrial boilers. The model is capable of estimating the energy, environmental, and cost impacts of alternative air emission regulations for new industrial boilers.

A.2 ANALYTICAL FRAMEWORK

A.2.1 Summary of Approach

IFCAM focuses on boiler fuel choice decisions between coal, oil, and natural gas. The model determines fuel choices for boilers in each of the 10 Federal regions using projected industrial fuel prices and total fossil fuel demand that primarily have been generated by the U.S. Department of Energy (DOE). IFCAM does not consider feedstock energy uses such as metallurgical coal or raw materials derived from petroleum or natural gas in the chemical industry.

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*Process engineering models simulate the effects of specific policies on new and existing technical alternatives through the application of direct engineering information. Other types of models are: econometric (mathematical equations solved simultaneously with coefficients estimated statistically from historical data); optimization (derivation of "best" solutions by means of algebraic procedures such as linear programming); simulation or systems dynamics (mathematical equations solved recursively with coefficients estimated from modeler's experience and intuition).

A very disaggregate representation of industrial energy uses is incorporated in IFCAM. Energy use is disaggregated into nine industrial subsectors having different growth rates and regional dispersions. Each of these industrial subsectors is further divided into boiler and process heat applications.

Industrial boiler energy use is disaggregated by new and existing boilers of different sizes and capacity utilizations rates. New and existing boilers are classified on the basis of the type of fuel they were designed to fire and whether they can be retrofitted to fire alternative fuels. Eight size classes are delineated for boilers. There are five capacity utilization rate categories for boilers.

The final level of disaggregation incorporates regional detail. Industrial boiler fuel use is divided among Air Quality Control Regions (AQCR's). Since a large number of regions are considered by IFCAM, the model can portray the variability in the environmental control costs of using the various fuels to fire boilers located throughout the country.

Current modeling capabilities for pollution control systems include only conventional technologies. The mid-term time horizon of IFCAM precludes significant market penetration of many of the advanced technologies still in the development stage.

Based on the characteristics of each combustor (size, operating rate, pollution control requirements, etc.), capital and nonfuel operating costs are generated for the options of choosing oil, gas, or coal. The fuel type associated with the lowest after-tax present value (including expected fuel expenses) of the total cost of generating energy over the investment period is selected.

The model generates energy, environmental, and cost impacts. Outputs include regional industrial boiler fossil energy demands by fuel type, air emissions, solid waste disposal requirements, energy penalties associated with the operation of pollution control equipment, demand for new pollution control equipment and boilers by size and type, and total costs (capital, annual operating, maintenance and fuel expenses) of using fossil energy to generate steam.

A.2.2 Capabilities

Four classes of energy policy measures can be analyzed with IFCAM: fuel taxes, investment incentives, energy regulatory policies, and environmental regulatory policies. A variety of tax credits and changes in the tax treatment of capital proposed to provide incentives to invest in coal-related equipment can be analyzed using the model.

Energy regulatory policies that target specific types of industrial energy uses to burn coal including new boilers and existing boilers designed to fire coal are modeled. Economic feasibility of complying with the Powerplant and Industrial Fuel Use Act (FUA) is an option in IFCAM that determines whether or not the cost of using coal substantially exceeds the cost of burning imported oil. The provisions of FUA are not applied in this impact analysis of New Source Performance Standards (NSPS) for industrial boilers.

Environmental regulatory policies that could affect fuel choice decisions also can be considered in IFCAM. These regulations can affect fuel choice by altering the relative costs of burning alternative fuels. Regulations relating to particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxide (NO_x) emissions from fuel-burning sources include State and local regulations and Federal NSPS.

IFCAM is capable of modeling alternative industrial boiler NSPS. IFCAM can simulate the use of various types of flue gas desulfurization (FGD) systems (some with combined SO_2/particulate matter emissions control), various types of post-combustion particulate matter emissions control, and two types of combustion modifications to control NO_x emissions. IFCAM's scrubber cost estimates are unique for each coal type and SO_2 emission regulation.

Several types of alternative NSPS specifications of SO_2 emissions control for industrial residual fuel oil and coal-fired boilers can be analyzed. For example, the regulation can vary by boiler size and can be specified as:

- A ceiling emission rate (ng of pollutant/Joule (lb of pollutant/MMBtu) of fuel burned)
- A recommended percentage removal (e.g., 90 percent removal of uncontrolled SO_2 emissions)
- A recommended percentage removal and a "floor" emissions rate (e.g., 90 percent removal but no lower than 258 ng/J (0.6 lb/MMBtu))
- A minimum percentage removal to be applied if the recommended percentage removal results in controlled emission rates lower than the "floor"

IFCAM can simulate the impact of alternative fuel price scenarios on industrial fuel mix. Regional fuel prices for distillate fuel oil, residual fuel oil (four sulfur classes), natural gas, and coal (9 types) are considered in the model.

The fuel choice decision is sensitive to non-fuel costs of burning alternate fuels. While the best available cost data are used, the model can evaluate the impact of any alternative cost estimates.

In addition to these three sets of factors, many other key variables affect fuel use. The model is designed, for example, to evaluate the effects of varying industrial production growth rates, and to alter the distribution of size and operating characteristics of new boilers.

A.2.3 Model Logic

Figure A-1 outlines the model structure and identifies key inputs, outputs, and major analytical steps.

Inputs 1, 2, and 3 - Energy Demand and Industrial Production: The level of industrial fossil fuel demand and nine industrial production growth rates by region are critical inputs to IFCAM. Although such inputs can be derived from many sources, in the past they have been taken from the Energy Consumption Data Base (ECDB), DOE projected industrial energy use, and the macroeconomic model that drives the DOE modeling framework.

Model Step #1 - Characterize Industrial Energy Use: This initial step breaks down the projected fossil fuel use by industrial sector, new and existing facilities, type of combustor (e.g., boiler versus process heater), size of boiler, and a variety of other classifications. These factors, discussed below, are significant because they:

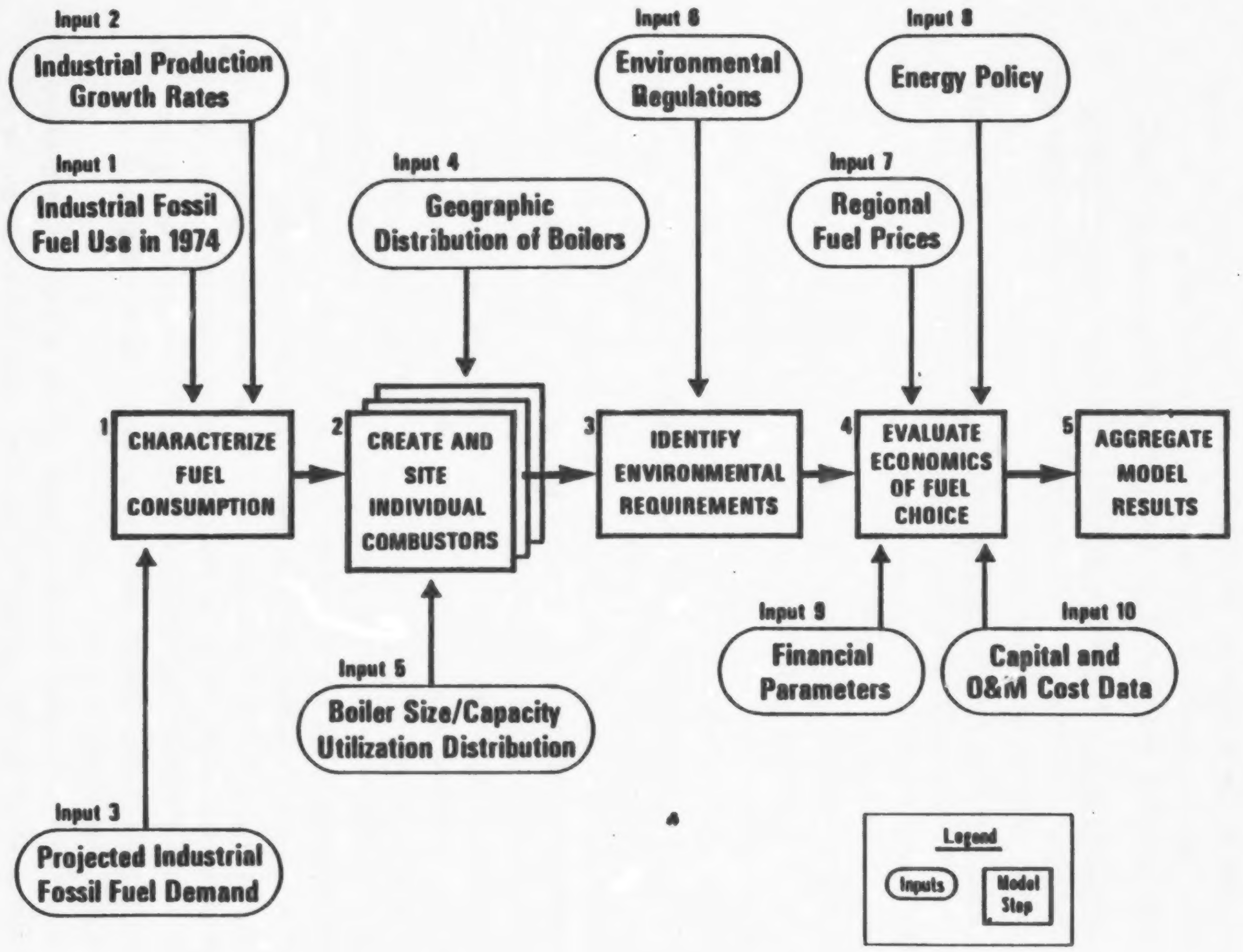
Input 2
Industrial Production Growth Rates
Input 1
Industrial Fossil Fuel Use in 1974
Input 4
Geographic Distribution of Boilers
Input 6
Environmental Regulations
Input 7
Regional Fuel Prices
Input 8
Energy Policy
1
CHARACTERIZE FUEL CONSUMPTION
2
CREATE AND SITE INDIVIDUAL COMBUSTORS
3
IDENTIFY ENVIRONMENTAL REQUIREMENTS
4
EVALUATE ECONOMICS OF FUEL CHOICE
5
AGGREGATE MODEL RESULTS
Input 3
Projected Industrial Fossil Fuel Demand
Input 5
Boiler Size/Capacity Utilization Distribution
Input 9
Financial Parameters
Input 10
Capital and O&M Cost Data
Legend
Inputs
Model Step

FIGURE A–1

IFCAM MODEL STRUCTURE

- Alter the costs of using alternate fuels (e.g., fuel costs vary according to industrial location)
- Determine the economics of fuel choice (considering such factors as the boiler's capacity utilization rate)
- Distinguish elements of energy use specifically targeted by energy policy measures (e.g., new boilers above a cutoff size).

Inputs 4 and 5 - Geographic and Boiler Size/Capacity Utilization Distributions: The geographic and boiler size/capacity utilization distributions are based on historical data.

Model Step #2 - Create and Site Individual Combustors: Energy uses from Step #1 are disaggregated into classes of individual boilers prior to further analysis. Boilers then are sited in AQCR's according to historical patterns of industrial location.

Input 6 - Environmental Regulations: A file of State and Federal air emissions regulations applicable to boilers is an important input to determine baseline costs and emissions. The file contains current regulations that vary by boiler size and fuel type on an AQCR basis.

Model Step #3 - Identify Environmental Regulations and Pollution Control Strategies: Emission limits for SO_2, PM, and NO_x applicable to individual boilers are assigned based on State and Federal regulations. Environmental regulations may increase the capital, operating, and fuel costs of a boiler by increasing the environmental control required or quality of fuel burned. Available pollution control technologies are identified in Table A-1. Compliance options are identified for each fuel type.

Inputs 7, 8, and 9 - Fuel Prices, Energy Policy, and Financial Parameters: Specifications for a particular model run and projection year are incorporated at this step. Specifications include the fuel price scenario, financial parameters, and energy regulatory policies.

Fuel price variations are used in IFCAM to model fuel taxes, natural gas price deregulation, or variations in price trajectories. Fuel prices can be varied for distillate fuel oil, residual fuel oil (four sulfur classes), coal (9 coal types), and natural gas. The price of each fuel type can differ by region.

Investment incentives considered have focused primarily on differential depreciation methods for coal-, oil-, or gas-fired units and on

TABLE A-1. INDUSTRIAL BOILER POLLUTION CONTROL TECHNOLOGIES IN IFCAM

Pollutant	Technology options
SO_2	Flue gas desulfurization - dual alkali[a] - lime spray drying[b] - sodium
PM	Single mechanical collector Dual mechanical collector Side stream separator Electrostatic precipitator Fabric filter
NO_x	Combustion modifications - low excess air - staged combustion air

[a] Tray type scrubber.

[b] Combined SO_2/PM emissions control system; includes a fabric filter.

increased investment tax credits (ITC's) for coal-derived fuel firing. The impacts of different depreciation methods and investment incentives are handled within the scope of the main model logic.

The coal conversion regulatory program established under the FUA targets boilers whose rated capacity is greater than 29 MW (100 MMBtu/hr) heat input. An economic test compares the total cost (capital, annual O&M and fuel) of burning coal to the total cost of burning imported oil to simulate legislative provisions related to economic exemptions. This procedure projects the level of increased coal use under the program, excluding any implementation problems. As noted earlier, the coal conversion economic test option in IFCAM is not currently utilized in evaluating alternative NSPS's for industrial boilers.

Input 10 - Capital and O&M Cost Data: Capital and O&M cost data relative to the range of boiler and pollution control equipment modeled in IFCAM are derived from numerous sources. Engineering cost data is revised on an as-needed basis when current estimates are refined or new estimates become available.

Model Step #4 - Evaluate Economics of Fuel Choice: Based on the characteristics of each boiler (size, operating rate, pollution control requirements, etc.), capital and non-fuel operating costs are estimated for the options of choosing oil, gas, or coal. The fuel type associated with the lowest after-tax present value (including capital and annual O&M and fuel expenses) of the cost of generating energy over the investment period then is selected.

The components of Net Present Value (NPV) can be divided into three major subsets: policy inputs, standard model assumptions, and key model variables. Policy inputs are depreciation life and method, ITC, and fuel prices. Standard model assumptions are construction period and corporate tax rate. These elements do not vary by boiler characteristics and represent standard investment assumptions. Key model variables -- capital costs, investment period, discount rate, annual fuel consumption by capacity utilization rate and size, and operation and maintenance (O&M) costs -- all vary with factors considered in the model (e.g., new or existing classification or environmental regulation).

A.3 KEY DATA INPUTS

This section summarizes key assumptions used in this analysis. These estimates may be revised in future model runs.

A.3.1 Cost Algorithms

The capital and operating costs of new boilers and associated pollution control equipment have been developed by several contractors. These costs were generalized to be expressed as algorithms. The algorithms are functions of a number of significant parameters.

The capital cost estimates include all installation costs (which are assumed not to vary by region) and indirect charges such as contingencies, land, and working capital. The boiler costs include auxiliary equipment such as the powerhouse and fuel and ash handling facilities. The annual non-fuel O&M cost estimates include labor, materials, parts, solid waste disposal and utility and commodity costs. The capital and annual non-fuel O&M cost estimates are assumed not to increase in real terms over time.

A.3.2 Financial Parameters

The fuel choice decision framework in IFCAM is based on the premise that industry will try to minimize the total costs of generating energy over the useful life of the facility. Specifically, industrial managers will select the fuel type with the lowest after-tax NPV of cash outflows for operating, fuel, and capital costs.

IFCAM models the key elements of the Energy Tax Act of 1978 (ETA) and the Economic Recovery Tax Act of 1981 (ERTA). The ETA influences after-tax NPV calculations by permitting investments in coal facilities to be depreciated using accelerated methods while requiring investments in new gas or oil boilers to be depreciated using a straight line method. Both new coal and oil/gas boilers are depreciated over 5 years. New coal-fired boilers qualify for the regular 10 percent investment tax credit (ITC), but new oil/gas boilers are excluded from the regular ITC. Special energy tax credits are not incorporated because they expired on December 31, 1982 for conventional coal systems.

IFCAM assumes an investment period of 15 years for new boilers. The corporate income tax rate is assumed to be 50 percent and includes Federal and local tax liabilities.

The discount rate in IFCAM represents the average real (not nominal) after-tax cost of capital. The real, after-tax discount rate is eight percent for new units.

A.3.3 Boiler Characteristics

IFCAM uses eight standard boiler sizes. Table A-2 summarizes key assumptions in each boiler size class. Costs and emission rates vary significantly with the boiler type and firing method. All new firetube boilers are single-fuel fired. All new watertube oil and gas boilers are dual-fuel fired.

A.3.4 Technology Limits

There are limits on the capability of control technology to remove air pollutants. The estimates used in this analysis for new coal-fired industrial boilers are listed in Tables A-3 and A-4.

A.3.5 Air Emissions Calculations

IFCAM projects air emissions for three pollutants: SO_2, PM, NO_x. The level of air emissions is a function of fuel type, boiler type, and the emission regulation. If the applicable regulation requires no emission reductions, the uncontrolled emission rates are the level of air emissions.

If the applicable regulation requires emission reductions in coal-fired boilers for SO_2, then the level of emissions is the following:

$$\text{Controlled } SO_2 \text{ emissions} = (R \times S \times (1-Sc)) + ((1-R) \times A)$$

where: S = uncontrolled annual average SO_2 emissions from coal combustion, ng/J (lb/MMBtu)

Sc = reduction required to meet standard (fraction)

R = 0.90 for lime spray drying FGD
= 0.95 for dual alkali and sodium FGD

A = uncontrolled SO_2 emissions from natural gas combustion (backup fuel)

This calculation assumes a reliability factor (R) for scrubbers and a low sulfur fuel standby option in the event of pollution control equipment malfunction.

TABLE A-2. IFCAM INDUSTRIAL BOILER SIZE/TYPE ASSUMPTIONS

Boiler size category, MW (MMBtu/hr) heat input		Type		
Range	Representative size	Coal	Residual oil/ natural gas[a]	Distillate oil/ natural gas[a]
3-9 (10-30)	6 (20)	Package, watertube, underfeed stoker	Package, firetube	Package, firetube
9-15 (30-50)	12 (40)	Package, watertube, underfeed stoker	Package, watertube	Package, watertube
15-22 (50-75)	18 (62)	Field-erected, watertube, spreader stoker	Package, watertube	Package, watertube
22-29 (75-100)	26 (87)	Field-erected, watertube, spreader stoker	Package, watertube	Package, watertube
29-44 (100-150)	37 (125)	Field-erected, watertube, spreader stoker or pulverized coal[b]	Package, watertube	Package, watertube
44-58 (150-200)	51 (175)	Field-erected, watertube, spreader stoker or pulverized coal[b]	Package, watertube	Package, watertube
58-73 (200-250)	66 (225)	Field-erected, watertube, spreader stoker or pulverized coal[b]	Two package, watertube[c]	Two package, watertube[c]
Greater than 73 (greater than 250)	95 (325)	Field-erected, watertube, pulverized coal	Two package, watertube[c]	Two package, watertube[c]

[a] Firetubes are single-fuel fired. Watertubes are dual-fuel fired.

[b] A mix is assumed in this size class.

[c] Each one-half of the "representative size" in the second column.

TABLE A-3. FGD TECHNOLOGY CONSTRAINTS IN IFCAM[a]

Technology	Limits
Dual alkali	90 percent[b] removal of uncontrolled SO_2 emissions for all coal types
Lime spray drying	90 percent[b] removal of uncontrolled SO_2 emissions for low sulfur coal types (less than 1.67 lb SO_2/MMBtu annual average); not applicable to higher sulfur coal types regardless of the required sulfur removal rate
Sodium	90 percent[b] removal of uncontrolled SO_2 emissions for all coal types

[a] U.S. Environmental Protection Agency.

[b] 30-day, rolling average basis.

TABLE A-4. PM EMISSIONS POLLUTION CONTROL TECHNOLOGY CONSTRAINTS IN IFCAM[a]

Technology	Minimum PM emission standard
Single mechanical collector	
stoker/bituminous	172 ng/J (0.40 lb/MMBtu)
stoker/subbituminous	344 ng/J (0.80 lb/MMBtu)
pulverized/all	430 ng/J (1.00 lb/MMBtu)
Dual mechanical collector	
stoker/bituminous	129 ng/J (0.30 lb/MMBtu)
stoker/subbituminous	258 ng/J (0.60 lb/MMBtu)
pulverized/all	344 ng/J (0.80 lb/MMBtu)
Side stream separator	
stoker/bituminous	64 ng/J (0.15 lb/MMBtu)
stoker/subbituminous	129 ng/J (0.30 lb/MMBtu)
pulverized/all	172 ng/J (0.40 lb/MMBtu)
Electrostatic precipitator	21 ng/J (0.05 lb/MMBtu)
Fabric filter	21 ng/J (0.05 lb/MMBtu)
Lime spray drying FGD[b]	21 ng/J (0.05 lb/MMBtu)
Dual alkali FGD/single mechanical collector	
high sulfur coal (greater than 3.5 lb SO_2/MMBtu)	129 ng/J (0.30 lb/MMBtu)
other coal types (less than 3.5 lb SO_2/MMBtu)	42 ng/J (0.10 lb/MMBtu)

[a] U.S. Environmental Protection Agency.

[b] Includes a fabric filter.

APPENDIX B. PROJECTED FUEL PRICES: REFERENCE PRICE SCENARIO

TABLE B-1. WORLD OIL PRICE FORECAST: REFERENCE PRICE SCENARIO[a]
(1982 $/bbl)

Year	Average refiner acquisition cost of imported crude oil
1985	25
1990	28
1995	32
2000	37

[a] Energy and Environmental Analysis, Inc.

TABLE B-2. PROJECTIONS OF INDUSTRIAL 3.0 PERCENT SULFUR RESIDUAL FUEL OIL PRICES[a]
(1982 $/MMBtu)

	Region	1985	1990	1995	2000
1.	New England	3.94	4.43	4.99	5.66
2.	New York/New Jersey	3.93	4.42	4.98	5.65
3.	Middle Atlantic	3.93	4.42	4.98	5.65
4.	South Atlantic	3.91	4.40	4.96	5.62
5.	Midwest	4.08	4.57	5.12	5.79
6.	Southwest	3.93	4.42	4.98	5.65
7.	Central	4.05	4.54	5.09	5.75
8.	North Central	3.74	4.23	4.79	5.47
9.	West	3.55	4.03	4.57	5.23
10.	Northwest	3.50	3.99	4.53	5.19

[a] Energy and Environmental Analysis, Inc. Reference price scenario.

TABLE B-3. PROJECTIONS OF INDUSTRIAL 1.6 PERCENT SULFUR RESIDUAL FUEL OIL PRICES[a] (1982 $/MMBtu)

Region	1985	1990	1995	2000
1. New England	4.21	4.73	5.32	6.04
2. New York/New Jersey	4.20	4.72	5.31	6.03
3. Middle Atlantic	4.20	4.72	5.31	6.03
4. South Atlantic	4.17	4.70	5.29	6.01
5. Midwest	4.34	4.86	5.45	6.17
6. Southwest	4.19	4.72	5.31	6.03
7. Central	4.31	4.83	5.42	6.14
8. North Central	4.00	4.53	5.13	5.85
9. West	3.82	4.33	4.91	5.61
10. Northwest	3.77	4.29	4.87	5.57

[a] Energy and Environmental Analysis, Inc. Reference price scenario.

TABLE B-4. PROJECTIONS OF INDUSTRIAL 0.8 PERCENT SULFUR RESIDUAL FUEL OIL PRICES[a]
(1982 $/MMBtu)

	Region	1985	1990	1995	2000
1.	New England	4.51	5.07	5.71	6.49
2.	New York/New Jersey	4.50	5.06	5.70	6.48
3.	Middle Atlantic	4.50	5.06	5.70	6.48
4.	South Atlantic	4.48	5.03	5.68	6.46
5.	Midwest	4.65	5.20	5.84	6.63
6.	Southwest	4.50	5.06	5.70	6.48
7.	Central	4.61	5.17	5.81	6.59
8.	North Central	4.31	4.87	5.51	6.30
9.	West	4.15	4.70	5.33	6.09
10.	Northwest	4.11	4.65	5.29	6.05

[a] Energy and Environmental Analysis, Inc. Reference price scenario.

TABLE B-5. PROJECTIONS OF INDUSTRIAL 0.3 PERCENT SULFUR RESIDUAL FUEL OIL PRICES[a]

(1982 $/MMBtu)

Region	1985	1990	1995	2000
1. New England	4.81	5.41	6.10	6.94
2. New York/New Jersey	4.80	5.40	6.09	6.93
3. Middle Atlantic	4.80	5.40	6.09	6.93
4. South Atlantic	4.78	5.37	6.07	6.91
5. Midwest	4.95	5.55	6.24	7.08
6. Southwest	4.80	5.40	6.09	6.93
7. Central	4.92	5.51	6.20	7.04
8. North Central	4.61	5.21	5.90	6.75
9. West	4.43	5.00	5.68	6.50
10. Northwest	4.38	4.96	5.64	6.45

[a] Energy and Environmental Analysis, Inc. Reference price scenario.

TABLE B-6. PROJECTIONS OF INDUSTRIAL NATURAL GAS PRICES[a]

(1982 $/MMBtu)

	Region	1985	1990	1995	2000
1.	New England	4.38	5.21	6.25	7.49
2.	New York/New Jersey	4.29	5.21	6.27	7.30
3.	Middle Atlantic	4.16	5.17	6.22	7.25
4.	South Atlantic	4.57	5.46	6.47	7.40
5.	Midwest	4.32	5.34	6.38	7.27
6.	Southwest	4.02	4.95	5.75	6.75
7.	Central	3.86	4.91	5.92	6.81
8.	North Central	3.68	4.47	5.27	6.12
9.	West	4.02	4.94	5.96	6.56
10.	Northwest	4.44	5.23	5.85	6.63

[a] Energy and Environmental Analysis, Inc. Reference price scenario.

APPENDIX C. PROJECTED FUEL PRICES: HIGHER OIL AND GAS PRICES SCENARIO

TABLE C-1. WORLD OIL PRICE FORECAST: HIGHER OIL AND GAS PRICES SCENARIO[a]
(1982 $/bbl)

Year	Average refiner acquisition cost of imported crude oil
1985	25.90
1990	31.90
1995	46.50
2000	57.40

[a] Case B. Energy Projections to the Year 2010. U.S. Department of Energy, Office of Policy, Planning and Analysis. DOE/PE-0029/2. October 1983.

TABLE C-2. PROJECTIONS OF INDUSTRIAL 3.0 PERCENT SULFUR RESIDUAL FUEL OIL PRICES[a] (1982 $/MMBtu)

Region	1985	1990	1995	2000
1. New England	4.07	5.05	6.93	8.40
2. New York/New Jersey	4.05	5.04	6.91	8.38
3. Middle Atlantic	4.05	5.04	6.91	8.38
4. South Atlantic	4.03	5.02	6.90	8.37
5. Midwest	4.18	5.17	7.05	8.51
6. Southwest	4.05	5.04	6.91	8.39
7. Central	4.15	5.14	7.02	8.52
8. North Central	3.89	4.87	6.75	8.24
9. West	3.72	4.68	6.47	7.90
10. Northwest	3.68	4.64	6.44	7.87

[a] Energy and Environmental Analysis, Inc. Higher oil and gas prices scenario.

TABLE C-3. PROJECTIONS OF INDUSTRIAL 1.6 PERCENT SULFUR RESIDUAL FUEL OIL PRICES[a]
(1982 $/MMBtu)

	Region	1985	1990	1995	2000
1.	New England	4.34	5.40	7.41	9.00
2.	New York/New Jersey	4.33	5.39	7.40	8.99
3.	Middle Atlantic	4.33	5.39	7.40	8.99
4.	South Atlantic	4.30	5.37	7.39	8.98
5.	Midwest	4.46	5.52	7.53	9.14
6.	Southwest	4.33	5.39	7.40	8.99
7.	Central	4.42	5.48	7.50	9.10
8.	North Central	4.16	5.22	7.24	8.83
9.	West	3.99	5.03	6.96	8.51
10.	Northwest	3.96	5.00	6.93	8.48

[a] Energy and Environmental Analysis, Inc. Higher oil and gas prices scenario.

TABLE C-4. PROJECTIONS OF INDUSTRIAL 0.8 PERCENT SULFUR RESIDUAL FUEL OIL PRICES[a]
(1982 $/MMBtu)

	Region	1985	1990	1995	2000
1.	New England	4.65	5.79	7.98	9.70
2.	New York/New Jersey	4.64	5.79	7.98	9.69
3.	Middle Atlantic	4.64	5.79	7.98	9.69
4.	South Atlantic	4.63	5.77	7.96	9.67
5.	Midwest	4.77	5.91	8.09	9.82
6.	Southwest	4.64	5.79	7.98	9.69
7.	Central	4.74	5.89	8.07	9.80
8.	North Central	4.47	5.63	7.80	9.52
9.	West	4.33	5.45	7.58	9.29
10.	Northwest	4.29	5.42	7.54	9.25

[a] Energy and Environmental Analysis, Inc. Higher oil and gas prices scenario.

TABLE C-5. PROJECTIONS OF INDUSTRIAL 0.3 PERCENT SULFUR RESIDUAL FUEL OIL PRICES[a]
(1982 $/MMBtu)

	Region	1985	1990	1995	2000
1.	New England	4.96	6.19	8.55	10.41
2.	New York/New Jersey	4.96	6.18	8.54	10.40
3.	Middle Atlantic	4.96	6.18	8.54	10.40
4.	South Atlantic	4.94	6.17	8.52	10.38
5.	Midwest	5.09	6.31	8.67	10.54
6.	Southwest	4.96	6.18	8.54	10.40
7.	Central	5.05	6.28	8.63	10.50
8.	North Central	4.79	6.01	8.37	10.24
9.	West	4.63	5.81	8.09	9.91
10.	Northwest	4.58	5.77	8.06	9.87

[a] Energy and Environmental Analysis, Inc. Higher oil and gas prices scenario.

TABLE C-6. PROJECTIONS OF INDUSTRIAL NATURAL GAS PRICES[a]
(1982 $/MMBtu)

	Region	1985	1990	1995	2000
1.	New England	4.43	5.56	7.37	9.29
2.	New York/New Jersey	4.35	5.54	7.36	9.01
3.	Middle Atlantic	4.29	5.52	7.36	9.00
4.	South Atlantic	4.63	5.85	7.69	9.19
5.	Midwest	4.42	5.69	7.55	8.95
6.	Southwest	4.08	5.41	6.96	8.57
7.	Central	3.92	5.27	7.08	8.54
8.	North Central	3.72	4.73	6.19	7.52
9.	West	4.05	5.23	6.91	8.19
10.	Northwest	4.45	5.45	7.03	8.15

[a] Energy and Environmental Analysis, Inc. Higher oil and gas prices scenario.

APPENDIX D. CHARACTERISTICS OF INDUSTRIAL COAL TYPES IN IFCAM

TABLE D-1. SULFUR DIOXIDE EMISSION RATES BY COAL TYPE[a]

Coal Type	Range		Average	
	ng/J	(lb/MMBtu)	ng/J	(lb/MMBtu)
Bituminous	<464	(<1.08)	408	(0.95)
	464-718	(1.08-1.67)	593	(1.38)
	718-1,075	(1.67-2.50)	894	(2.08)
	1,075-1,432	(2.50-3.33)	1,225	(2.85)
	1,432-2,150	(3.33-5.00)	1,784	(4.15)
	>2,150	(>5.00)	2,382	(5.54)
Subbituminous	<464	(<1.08)	408	(0.95)
	464-718	(1.08-1.67)	593	(1.38)
	718-1,075	(1.67-2.50)	894	(2.08)

[a] ICF Incorporated. Average annual (not 30-day, rolling-average) values.

TABLE D-2. AVERAGE ASH CONTENT BY REGION (BITUMINOUS COAL TYPES)[a]
(percentage, moist)

Region	lb SO_2/MMBtu					
	<1.08	1.08-1.67	1.67-2.50	2.50-3.33	3.33-5.00	>5.00
1. New England	11.9	11.9	13.0	13.0	13.0	13.0
2. New York/New Jersey	11.9	11.9	11.4	13.0	13.0	13.0
3. Middle Atlantic	11.8	12.4	12.6	12.2	13.0	13.0
4. South Atlantic	11.7	12.3	12.3	11.9	11.9	11.8
5. Midwest	11.0	11.0	10.5	10.9	12.2	12.0
6. Southwest	12.1	11.8	15.0	11.8	12.2	12.3
7. Central	10.0	12.4	12.4	11.1	11.1	11.1
8. North Central	10.0	10.0	10.0	-	-	-
9. West	11.3	11.3	16.3	-	-	-
10. Northwest	10.0	10.0	10.0	-	-	-

[a] ICF Incorporated.

TABLE D-3. AVERAGE ASH CONTENT BY REGION (SUBBITUMINOUS COAL TYPES)[a] (percentage, moist)

Region	lb SO_2/MMBtu		
	<1.08	1.08-1.67	1.67-2.50
1. New England	-	-	-
2. New York/New Jersey	-	-	-
3. Middle Atlantic	-	-	-
4. South Atlantic	-	-	-
5. Midwest	6.9	6.9	6.9
6. Southwest	7.3	7.3	7.3
7. Central	6.0	6.0	6.0
8. North Central	8.4	6.9	6.9
9. West	7.3	7.3	7.3
10. Northwest	10.0	10.0	10.0

[a] ICF Incorporated.

TABLE D-4. AVERAGE HEAT CONTENT BY REGION (BITUMINOUS COAL TYPES)[a]

J/g (MMBtu/short ton)

Region	lb SO_2/MMBtu					
	<1.08	1.08-1.67	1.67-2.50	2.50-3.33	3.33-5.00	>5.00
1. New England	29.66 (25.50)	29.66 (25.50)	29.77 (25.60)	30.59 (26.30)	29.89 (25.70)	28.78 (24.75)
2. New York/New Jersey	29.08 (25.00)	29.31 (25.20)	29.66 (25.50)	30.35 (26.10)	29.89 (25.70)	29.31 (25.20)
3. Middle Atlantic	29.41 (25.29)	29.54 (25.40)	29.56 (25.42)	29.47 (25.34)	29.08 (25.00)	28.91 (24.86)
4. South Atlantic	29.59 (25.44)	29.62 (25.47)	29.59 (25.44)	28.91 (24.86)	27.49 (23.64)	26.40 (22.70)
5. Midwest	29.13 (25.05)	29.20 (25.11)	27.44 (23.59)	26.71 (22.97)	26.67 (22.93)	27.12 (23.32)
6. Southwest	28.88 (24.83)	24.04 (20.67)	23.90 (20.55)	28.23 (24.27)	28.21 (24.26)	27.78 (23.89)
7. Central	27.75 (23.86)	28.30 (24.33)	27.98 (24.06)	26.62 (22.89)	26.54 (22.82)	26.75 (23.00)
8. North Central	25.24 (21.70)	24.03 (20.66)	23.92 (20.57)	- -	- -	- -
9. West	24.43 (21.01)	23.49 (20.20)	22.85 (19.65)	- -	- -	- -
10. Northwest	25.45 (21.88)	25.45 (21.88)	25.45 (21.88)	- -	- -	- -

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[a] ICF Incorporated.

TABLE D-5. AVERAGE HEAT CONTENT BY REGION

(SUBBITUMINOUS COAL TYPES)[a]
J/g (MMBtu/short ton)

Region	lb SO_2/MMBtu		
	<1.08	1.08-1.67	1.67-2.50
1. New England	- -	- -	- -
2. New York/New Jersey	- -	- -	- -
3. Middle Atlantic	- -	- -	- -
4. South Atlantic	- -	- -	- -
5. Midwest	20.53 (17.65)	20.53 (17.65)	20.53 (17.65)
6. Southwest	19.93 (17.14)	19.93 (17.14)	19.93 (17.14)
7. Central	19.77 (17.00)	19.77 (17.00)	19.77 (17.00)
8. North Central	20.40 (17.54)	20.05 (17.24)	20.05 (17.24)
9. West	21.52 (18.50)	21.52 (18.50)	21.52 (18.50)
10. Northwest	22.10 (19.00)	22.10 (19.00)	22.10 (19.00)

[a] ICF Incorporated.

APPENDIX E. DELIVERED INDUSTRIAL COAL PRICE FORECAST

- Reference: Memorandum from C. Ebert (ICF Incorporated) to J. Greenwald (EPA). Revised Industrial Coal Prices for Industrial NSPS Analyses. May 31, 1984. Attachment A.
- Converted from January 1983 dollars to 1982 dollars using the average annual 1982 and fourth quarter 1982 GNP implicit price deflators.

DELIVERED INDUSTRIAL COAL PRICE FORECAST[a]
(1982 $/MMBtu)

Region	Coal type	Sulfur content (lb SO_2/MMBtu)	1985	1990	1995	2000
1. New England	Bituminous	<1.08	3.35	3.62	3.75	3.87
		1.08 - 1.67	3.21	3.58	3.71	3.86
		1.67 - 2.50	3.19	3.52	3.65	3.75
		2.50 - 3.33	3.09	3.33	3.44	3.54
		3.33 - 5.00	2.67	2.96	3.23	3.46
		>5.00	2.84	3.11	3.25	3.48
2. New York/ New Jersey	Bituminous	<1.08	3.18	3.39	3.48	3.60
		1.08 - 1.67	3.03	3.31	3.45	3.57
		1.67 - 2.50	2.90	3.17	3.28	3.41
		2.50 - 3.33	2.77	3.01	3.12	3.21
		3.33 - 5.00	2.34	2.63	2.91	3.10
		>5.00	2.43	2.69	2.89	3.05
3. Middle Atlantic	Bituminous	<1.08	2.75	3.01	3.14	3.26
		1.08 - 1.67	2.49	2.82	2.96	3.10
		1.67 - 2.50	2.42	2.74	2.88	2.98
		2.50 - 3.33	2.37	2.66	2.77	2.86
		3.33 - 5.00	1.99	2.27	2.45	2.68
		>5.00	1.99	2.25	2.43	2.62
4. South Atlantic	Bituminous	<1.08	2.66	3.07	3.23	3.35
		1.08 - 1.67	2.47	2.83	3.05	3.21
		1.67 - 2.50	2.45	2.82	3.03	3.17
		2.50 - 3.33	2.40	2.73	2.93	3.08
		3.33 - 5.00	2.44	2.67	2.81	2.93
		>5.00	2.32	2.48	2.62	2.79

[a] ICF Incorporated.

DELIVERED INDUSTRIAL COAL PRICE FORECAST[a]
(1982 \$/MMBtu)
(Continued)

Region	Coal type	Sulfur content (lb SO_2/MMBtu)	1985	1990	1995	2000
5. Midwest	Bituminous	<1.08	2.91	3.18	3.33	3.44
		1.08 - 1.67	2.69	3.04	3.21	3.37
		1.67 - 2.50	2.67	2.97	3.08	3.18
		2.50 - 3.33	2.53	2.82	2.94	3.04
		3.33 - 5.00	2.30	2.56	2.69	2.80
		>5.00	2.19	2.39	2.50	2.63
	Subbituminous	<1.08	3.19	3.26	3.32	3.38
		1.08 - 1.67	3.15	3.22	3.27	3.32
		1.67 - 2.50	3.13	3.19	3.26	3.27
6. Southwest	Bituminous	<1.08	2.85	3.18	3.38	3.56
		1.08 - 1.67	2.75	3.05	3.26	3.42
		1.67 - 2.50	2.75	3.05	3.25	3.35
		2.50 - 3.33	2.85	3.05	3.19	3.33
		3.33 - 5.00	2.77	2.96	3.10	3.18
		>5.00	2.68	2.84	2.93	3.05
	Subbituminous	<1.08	3.21	3.35	3.46	3.57
		1.08 - 1.67	3.09	3.26	3.34	3.46
		1.67 - 2.50	3.04	3.20	3.29	3.39
7. Central	Bituminous	<1.08	2.81	3.01	3.14	3.22
		1.08 - 1.67	2.77	2.95	3.04	3.15
		1.67 - 2.50	2.78	2.94	3.01	3.05
		2.50 - 3.33	2.55	2.78	2.93	3.07
		3.33 - 5.00	2.44	2.52	2.58	2.63
		>5.00	2.25	2.35	2.44	2.57
	Subbituminous	<1.08	2.59	2.62	2.71	2.78
		1.08 - 1.67	2.53	2.58	2.66	2.72
		1.67 - 2.50	2.63	2.62	2.68	2.67

[a] ICF Incorporated.

DELIVERED INDUSTRIAL COAL PRICE FORECAST[a]
(1982 \$/MMBtu)
(Continued)

Region	Coal type	Sulfur content (lb SO_2/MMBtu)	1985	1990	1995	2000
8. North Central	Bituminous	<1.08	1.76	1.90	1.98	2.07
		1.08 - 1.67	1.61	1.74	1.90	2.01
		1.67 - 2.50	1.70	1.81	1.88	1.86
	Subbituminous	<1.08	1.22	1.32	1.41	1.52
		1.08 - 1.67	1.17	1.32	1.42	1.45
		1.67 - 2.50	1.19	1.21	1.28	1.33
9. West	Bituminous	<1.08	2.54	2.69	2.75	2.91
		1.08 - 1.67	2.39	2.64	2.90	3.05
		1.67 - 2.50	2.40	2.64	2.81	2.92
	Subbituminous	<1.08	2.62	2.71	2.83	2.92
		1.08 - 1.67	2.52	2.61	2.72	2.84
		1.67 - 2.50	2.48	2.56	2.60	2.69
10. Northwest	Bituminous	<1.08	2.92	3.06	3.13	3.27
		1.08 - 1.67	2.63	2.80	2.99	3.18
		1.67 - 2.50	2.59	2.72	2.83	2.88
	Subbituminous	<1.08	2.38	2.59	2.62	2.71
		1.08 - 1.67	2.40	2.48	2.59	2.67
		1.67 - 2.50	1.93	1.99	2.08	2.19

[a] ICF Incorporated.

APPENDIX F

IFCAM PROJECTIONS FOR 1990 BY BOILER SIZE CLASS

This appendix summarizes IFCAM forecasts of total SO_2 emissions, annualized costs, and fossil fuel demand in 1990 from new industrial fossil fuel-fired boilers installed between 1985 and 1990 and each larger than 29 MW (100 MMBtu/hr) heat input capacity. Results are presented for both fuel price scenarios (reference Section 2.2.3) and for each alternative SO_2 NSPS emissions standard (reference Section 3.1).

In these tables, "gas" is natural gas and "oil" is residual fuel oil.

TABLE F-1. COMPARISON OF IFCAM PROJECTIONS FOR 1990[a]

Fuel price scenario	Alternative control level						
	Baseline	I	II	III	IV	V	VI
Reference							
SO_2 emissions (10^3 short tons)	279	204	106	102	39	47	16
Annualized costs[b] (10^6 1982 $)	3,349	3,357	3,406	3,408	3,476	3,474	3,482
Fuel (10^{12} Btu)							
coal	23	17	17	9	26	26	26
oil	323	329	257	257	206	205	178
gas	152	153	225	232	267	267	294
Higher oil and gas prices							
SO_2 emissions (10^3 short tons)	326	148	114	46	34	30	16
Annualized costs[b] (10^6 1982 $)	3,725	3,735	3,743	3,754	3,757	3,758	3,757
Fuel (10^{12} Btu)							
coal	284	261	248	153	153	153	147
oil	7	0	0	0	0	0	0
gas	207	237	250	345	345	345	351

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990 and each larger than 29 MW (100 MMBtu/hr) heat input capacity.

[b] Includes capital, operating, maintenance and fuel costs for the boiler and pollution control equipment.

TABLE F-2. REGULATORY BASELINE PROJECTIONS FOR 1990 BY BOILER SIZE CLASS[a]

Fuel price scenario	Boiler size class, MW (MMBtu/hr) 29-44 (100-150)	44-58 (150-200)	58-73 (200-250)	>73 (>250)	Total
Reference					
SO_2 emissions (10^3 short tons)	105	82	52	41	279
Annualized costs[b] (10^6 1982 $)	901	729	445	1,275	3,349
Fuel (10^{12} Btu)					
coal	4	1	6	13	23
oil	99	86	46	92	323
gas	26	24	15	87	152
Higher oil and gas prices					
SO_2 emissions (10^3 short tons)	74	108	86	59	326
Annualized costs[b] (10^6 1982 $)	1,008	838	493	1,386	3,725
Fuel (10^{12} Btu)					
coal	40	70	48	126	284
oil	7	0	0	0	7
gas	82	41	19	65	207

[a] New industrial fossil fuel-fired boilers installed between 1986 and 1990.

[b] Includes capital, operating, maintenance and fuel costs for the boiler and pollution control equipment.

TABLE F-3. ALTERNATIVE CONTROL LEVEL I PROJECTIONS FOR 1990 BY BOILER SIZE CLASS[a]

Fuel price scenario	Boiler size class, MW (MMBtu/hr)				
	29-44 (100-150)	44-58 (150-200)	58-73 (200-250)	>73 (>250)	Total
Reference					
SO_2 emissions (10^3 short tons)	69	59	35	40	204
Annualized costs[b] (10^6 1982 $)	906	733	444	1,275	3,357
Fuel (10^{12} Btu)					
coal	3	1	0	13	17
oil	100	86	51	92	329
gas	26	24	16	87	153
Higher oil and gas prices					
SO_2 emissions (10^3 short tons)	24	37	29	58	148
Annualized costs[b] (10^6 1982 $)	1,013	836	500	1,387	3,735
Fuel (10^{12} Btu)					
coal	37	55	43	126	261
oil	0	0	0	0	0
gas	92	56	24	65	237

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990.

[b] Includes capital, operating, maintenance and fuel costs for the boiler and pollution control equipment.

TABLE F-4. ALTERNATIVE CONTROL LEVEL II PROJECTIONS FOR 1990 BY BOILER SIZE CLASS[a]

Fuel price scenario	Boiler size class, MW (MMBtu/hr) 29-44 (100-150)	44-58 (150-200)	58-73 (200-250)	>73 (>250)	Total
Reference					
SO_2 emissions (10^3 short tons)	28	24	14	40	106
Annualized costs[b] (10^6 1982 $)	926	749	456	1,275	3,406
Fuel (10^{12} Btu)					
coal	3	1	0	13	17
oil	70	60	34	92	257
gas	56	50	33	87	225
Higher oil and gas prices					
SO_2 emissions (10^3 short tons)	11	25	20	58	114
Annualized costs[b] (10^6 1982 $)	1,009	844	504	1,387	3,743
Fuel (10^{12} Btu)					
coal	23	55	43	126	248
oil	0	0	0	0	0
gas	105	56	24	65	250

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990.

[b] Includes capital, operating, maintenance and fuel costs for the boiler and pollution control equipment.

TABLE F-5. ALTERNATIVE CONTROL LEVEL III PROJECTIONS FOR 1990 BY BOILER SIZE CLASS[a]

Fuel price scenario	Boiler size class, MW (MMBtu/hr) 29-44 (100-150)	44-58 (150-200)	58-73 (200-250)	>73 (>250)	Total
Reference					
SO_2 emissions (10^3 short tons)	27	23	14	38	102
Annualized costs[b] (10^6 1982 $)	927	749	456	1,276	3,408
Fuel (10^{12} Btu)					
coal	1	0	0	9	9
oil	70	60	34	92	257
gas	58	51	33	91	232
Higher oil and gas prices					
SO_2 emissions (10^3 short tons)	4	7	5	30	46
Annualized costs[b] (10^6 1982 $)	1,011	832	500	1,411	3,754
Fuel (10^{12} Btu)					
coal	12	23	17	101	153
oil	0	0	0	0	0
gas	117	88	50	90	345

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990.

[b] Includes capital, operating, maintenance and fuel costs for the boiler and pollution control equipment.

TABLE F-6. ALTERNATIVE CONTROL LEVEL IV PROJECTIONS FOR 1990 BY BOILER SIZE CLASS[a]

Fuel price scenario	Boiler size class, MW (MMBtu/hr)				
	29-44 (100-150)	44-58 (150-200)	58-73 (200-250)	>73 (>250)	Total
Reference					
SO_2 emissions (10^3 short tons)	9	9	5	15	39
Annualized costs[b] (10^6 1982 $)	943	762	461	1,310	3,476
Fuel (10^{12} Btu)					
coal	0	0	0	26	26
oil	57	57	33	59	206
gas	72	54	34	107	267
Higher oil and gas prices					
SO_2 emissions (10^3 short tons)	3	5	4	22	34
Annualized costs[b] (10^6 1982 $)	1,011	833	501	1,412	3,757
Fuel (10^{12} Btu)					
coal	12	23	17	101	153
oil	0	0	0	0	0
gas	117	88	50	90	345

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990.

[b] Includes capital, operating, maintenance and fuel costs for the boiler and pollution control equipment.

TABLE F-7. ALTERNATIVE CONTROL LEVEL V PROJECTIONS FOR 1990 BY BOILER SIZE CLASS[a]

Fuel price scenario	Boiler size class, MW (MMBtu/hr) 29-44 (100-150)	44-58 (150-200)	58-73 (200-250)	>73 (>250)	Total
Reference					
SO_2 emissions (10^3 short tons)	13	13	8	13	47
Annualized costs[b] (10^6 1982 $)	942	761	460	1,311	3,474
Fuel (10^{12} Btu)					
coal	0	0	0	26	26
oil	57	57	33	59	206
gas	72	54	34	107	267
Higher oil and gas prices					
SO_2 emissions (10^3 short tons)	3	5	3	19	30
Annualized costs[b] (10^6 1982 $)	1,011	833	501	1,414	3,758
Fuel (10^{12} Btu)					
coal	12	23	17	101	153
oil	0	0	0	0	0
gas	117	88	50	90	345

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990.

[b] Includes capital, operating, maintenance and fuel costs for the boiler and pollution control equipment.

TABLE F-8. ALTERNATIVE CONTROL LEVEL VI PROJECTIONS FOR 1990 BY BOILER SIZE CLASS[a]

Fuel price scenario	Boiler size class, MW (MMBtu/hr)				
	29-44 (100-150)	44-58 (150-200)	58-73 (200-250)	>73 (>250)	Total
Reference					
SO_2 emissions (10^3 short tons)	4	4	3	6	16
Annualized costs[b] (10^6 1982 \$)	945	763	461	1,313	3,482
Fuel (10^{12} Btu)					
coal	0	0	0	26	26
oil	44	51	32	52	178
gas	85	60	35	113	294
Higher oil and gas prices					
SO_2 emissions (10^3 short tons)	2	2	2	10	16
Annualized costs[b] (10^6 1982 \$)	1,011	829	501	1,415	3,757
Fuel (10^{12} Btu)					
coal	12	17	17	101	147
oil	0	0	0	0	0
gas	117	94	50	90	351

[a] New industrial fossil fuel-fired boilers installed between 1985 and 1990.

[b] Includes capital, operating, maintenance and fuel costs for the boiler and pollution control equipment.